# AIR QUALITY PERMIT

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| Issued to: | ConocoPhillips Company | Permit #2619-19 |
| | Billings Refinery | Application Complete: 03/01/04 |
| | P.O. Box 30198 | Preliminary Determination Issued: 04/02/04 |
| | Billings, MT 59107-0198 | Department Decision Issued: 05/11/04 |
| | | Permit Final: 05/27/04 |
| | | AFS#: 111-0011 |

An air quality permit, with conditions, is hereby granted to ConocoPhillips Company, Billings Refinery (ConocoPhillips), pursuant to Sections 75-2-204 and 211 of the Montana Code Annotated (MCA), as amended, and the Administrative Rules of Montana (ARM) 17.8.740, *et seq.*, as amended, for the following:

## SECTION I: Permitted Facilities

ConocoPhillips operates a petroleum refinery and all refinery equipment, including, but not limited to, the following:

A. Existing Sources – ConocoPhillips

| Emission Point | Source |
|---|---|
| 1 | Four (4) Boilers |
| 2 | Heater #1 |
| 3 | Heater #2 |
| 4 | Heater #4 |
| 5 | Heater #5 |
| 6 | Coker Heater |
| 7 | Heater #10 |
| 8 | Heater #11 |
| 9 | Heater #12 |
| 10 | Heater #13 |
| 11 | Heater #14 |
| 12 | Heater #15 |
| 13 | Heater #16 |
| 14 | Heater #17 |
| 15 | Heater #18 |
| 16 | Heater #19 |
| 17 | Heater #20 |
| 18 | Heater #21 |
| 19 | Heater #22 |
| 20 | Heater #23 |
| 21 | Heater #24 |
| 22 | Fluid Catalytic Cracking Unit (FCCU) |
| 23 | Flare (refinery) |
| 24 | Storage Tanks |
| 25 | Bulk Loading - Gasoline and Distillate |
| 26 | Fugitive volatile organic compounds (VOC) Emissions |
| 27 | Corrugated Plate Intercptor (CPI) Separator System |
| 28 | Recycle Hydrogen Heater |
| 29 | Fractionator Feed Heater |
| 30 | 20.0-million standard cubic feet per day (MMscfd) Hydrogen Plant SMR Heater |

| | |
|---|---|
| 31 | Polymer Modified Asphalt (PMA) Process Heater (H-3201) |
| 32 | Saturate Gas Plant |
| 41 | Ultra Low Sulfur Diesel (ULSD) NH-1 - No.5 Hydrodesulfurization (HDS) Charge Heater |
| 42 | ULSD NH-2 - No.5 HDS Stabilizer Reboiler Heater |
| 43 | ULSD NH-3 - No.2 Hydrogen ($H_2$) Unit Reformer Heater |

B. Existing Sources - Jupiter Sulphur, Inc. (Jupiter), operated by Kerley Enterprises.

| Emission Point | Source |
|---|---|
| 1 | Main Stack (S-101/S-401) |
| 2 | Jupiter Flare Stack |

The Jupiter Recovery Facility consists of three primary units: the existing Ammonium Thiosulfate (ATS) Plant, the existing Ammonium Sulfide Unit (ASD), and the Claus Sulfur and Tail Gas Treating Units (TGTU). The addition of the units increased the total sulfur recovery capacity of the facility from 110 Long Tons per Day (LT/D) to 170 LT/D of sulfur. Jupiter's new Claus Sulfur and TGTUs shall have three parallel single-stage high-efficiency gas filters for final particulate and sulfur dioxide ($SO_2$) control. All emissions from these three primary processes are vented to Jupiter's main stack.

C. Current Permit Action

On February 3, 2004, the Montana Department of Environmental Quality (Department) received a Montana Air Quality Permit Application from ConocoPhillips to modify Permit #2619-18 to add a new HDS Unit (No.5), a new sour water stripper (No.3 SWS), and a new $H_2$ Unit. On March 1, 2004, the Department deemed the application complete upon submittal of additional information. The addition of these new units adds three new heaters, 41, 42, and 43, each equipped with low nitrogen oxides ($NO_X$) burners (LNB) and flue gas recirculation (FGR) commonly referred to as ultra-low $NO_X$ burners (ULNB). Additionally, ConocoPhillips proposes to retrofit existing external floating roof tank T-110 with a cover to allow nitrogen blanketing of the tank, to install a new storage vessel (No.5 HDS Feed storage tank) under emission point 24 above, to store feed and off-specification material for the No.5 HDS Unit, and to provide the No.1 $H_2$ Unit with the flexibility to burn refinery fuel gas (RFG). The new equipment is being added to meet the new Environmental Protection Agency (EPA)-required highway ULSD fuel sulfur standard of 100% of highway diesel that meets the 15 parts per million (ppm) highway diesel fuel maximum sulfur specification by June 1, 2006. By meeting the June 1, 2006, deadline, ConocoPhillips may claim a two-year extension for the phase in of the requirements of the Tier Two Gasoline/Sulfur Rulemaking. This permitting action results in $NO_X$ and VOC emissions that exceed Prevention of Significant Deterioration (PSD) significance levels. Other changes are also contained in this permit. Previously in permit condition II.A.1 it was stated that the emergency flare tip must be based at 148-feet elevation. After a physical survey of the emergency flare it was determined that the actual height of the flare tip is 141.5-feet elevation. The current permit changes permit condition II.A.1 from 148-feet of elevation of 142-feet plus or minus 2 feet of elevation and changes the reference from ARM 17.8.752 to ARM 17.8.749. Permit #2619-19 has also been updated to reflect current permit language and rule references used by the Department.

SECTION II: Conditions and Limitations

A. Emission Control Requirements

ConocoPhillips shall install, operate and maintain the following emission control equipment to provide the maximum air pollution control for which it was designed:

1. The Emergency flare must be equipped and operated with a steam injection system (ARM 17.8.752). The flare tip is to be based at a minimum of 142-feet plus or minus 2 feet elevation (ARM 17.8.749).

2. The Jupiter flare must be equipped and operated with a steam injection system (ARM 17.8.752). The flare tip is to be based at 213-feet elevation (ARM 17.8.749).

3. Storage tank #49 shall be equipped with an internal floating roof with a double rim seal system for VOC loss control (ARM 17.8.752).

4. Storage tanks #4510 and #4511 shall be equipped with internal floating roofs with double rim seals or a liquid-mounted seal system for VOC loss control (ARM 17.8.752).

5. Storage tank #162 shall be equipped with a fixed roof that includes a roof-top vacuum breaker vent (ARM 17.8.340).

6. The C-23 compressor station shall be operated and maintained as follows (ARM 17.8.752):

    a. All valves used are high-quality valves containing high-quality packing;

    b. All open-ended valves are of the same quality as the valves described above. They will have plugs, caps, or a second valve installed on the open end;

    c. All pipe and tower flanges are installed using process compatible gasket material;

    d. All pumps are fitted with the highest quality state-of-the-art mechanical seals, as appropriate;

    e. A VOC monitoring and maintenance program is instituted as described in 40 Code of Federal Regulations (CFR) 60.482-2, 40 CFR 60.482-4 thru 10, 40 CFR 60.483-1 and 2, 40 CFR 60.485, 40 CFR 60.486 (b-k), and 40 CFR 60.486 (c-e) and;

    f. If monitoring or scheduled inspections indicate failure or leakage of the compressor seal system, then the seals shall be repaired as soon as practicable (but not later than 15 calendar days after it is detected), except as provided in 40 CFR 60.482-9.

7. ConocoPhillips shall comply with all applicable requirements of ARM 17.8.340, which reference 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS):

    a. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS Subpart as listed below:

b. Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units shall apply to all affected boilers at the facility for which were constructed after June 19, 1984, are larger than 100 MMBtu/hr, and combust fossil fuel;

ConocoPhillips shall comply with all applicable requirements of Subpart Db, for all affected boilers at the facility.

c. Subpart J - Standards of Performance for Petroleum Refineries shall apply to all of the heaters and boilers at the ConocoPhillips refinery and the Claus units at the Jupiter sulfur recovery facility and any other affected equipment.

Compliance with the limits of this standard shall be determined by the hydrogen sulfide ($H_2S$) Continuous Emission Monitor System (CEMS) on the fuel gas system that supplies the heaters and boilers (ConocoPhillips Consent Decree, paragraph 69);

d. Subpart Ka - Standards of Performance for Volatile Organic Liquid Storage Vessels shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after May 18, 1978, and prior to July 23, 1984. These requirements shall be as specified in 40 CFR 60.110a through 60.115a. The affected tanks include, but are not limited to, the following:

<u>Tank Number</u>
#100-Ka*
#101-Ka*
#102-Ka
#104-Ka*

* Currently exempt from all emission control provisions due to vapor pressure of materials stored;

e. Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984. These requirements shall be as specified in 40 CFR 60.110b through 60.117b. The affected tanks include, but are not limited to, the following:

<u>Tank Number</u>
#36-Kb
#72-Kb
#107-Kb*
#110-Kb
#162-Kb*
#T-3201*
#T-4523
No.5 HDS Feed storage tank

* Currently exempt from all emission control provisions due to vapor pressure of materials stored;

f. Subpart UU - Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture shall apply to, but not be limited to, asphalt storage tank T-3201 and any other applicable storage tanks that commenced construction or modification after May 26, 1981. Asphalt storage tank T-3201 shall comply with the standards in 40 CFR 60.472(c);

g. Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries shall apply to, but not be limited to, the delayed coker unit, cryogenic unit, hydrogen membrane unit, gasoline merox unit, crude vacuum unit, gas oil hydrotreater unit (consisting of a reaction section, fractionation section, and an amine treating section), 20.0-MMscfd hydrogen plant feed system, Alkylation Unit Butane Defluorinator Project (consisting of heat exchangers; X-453, X-223, X-450, X-451, X-452, pumps; P-646, Vessels; D-130, D-359, D-360), PMA process unit, Alkylation Unit Depropanizer Project; fugitive components associated with boilers B-7 and B-8; the fugitive components associated with the new No.2 $H_2$ Unit and the new No.5 HDS Unit; and any other applicable equipment constructed or modified after January 4, 1983:

   i. All valves used shall be high-quality valves containing high-quality packing;

   ii. All open-ended valves shall be of the same quality as the valves described above. They will have plugs, caps or a second valve installed on the open end;

   iii. All pipe and tower flanges shall be installed using process compatible gasket material;

   iv. All pumps shall be fitted with the highest quality state-of-the-art mechanical seals, as appropriate;

   v. A monitoring and maintenance program as described under New Source Performance Standards (40 CFR Part 60, Subpart VV) shall be instituted; and

   vi. The affected equipment within the PMA process unit shall be visually monitored for equipment leaks as outlined in 40 CFR 60.482-8.

h. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems, shall apply to, but not be limited to, the coker unit drain system, desalter wastewater break tanks, CPI separators, gas oil hydrotreater, 20.0-MMscfd hydrogen plant, C-23 compressor station, Alkylation Unit Butane Defluorinator Project, Alkylation Unit Depropanizer Project, the new individual drain system in the No.2 $H_2$ Unit and the No.5 HDS Unit, and any other applicable equipment:

   i. All process drains shall consist of tightly sealed caps or P-leg traps for sewer drains with intermittent flow;

ii. The secondary oil/water separator is an oil/water (CPI) separator with hydrocarbon collection and recovery equipment; and

iii. All equipment is operated and maintained as required by 40 CFR Part 60, Subpart QQQ, New Source Performance Standards.

8. ConocoPhillips shall comply with all applicable requirements of ARM 17.8.341, which references 40 CFR Part 61, National Emission Standards for Hazardous Air Pollutants:

a. Subpart A - General Provisions applies to all equipment or facilities subject to a National Emission Standards for Hazardous Air Pollutants (NESHAP) subpart as listed below;

b. Subpart FF - National Emission Standards for Benzene Waste Operations shall apply to, but not be limited to, all new or recommissioned wastewater sewer drains associated with the Alkylation Unit Depropanizer Project, the Refinery's existing sewer system, the new individual drain system for the waste streams associated with the No.2 $H_2$ Unit and the No.5 HDS Unit, and Tanks 34 and 35; and

c. Subpart M - National Emission Standard for Asbestos shall apply to, but not be limited to, the demolition and/or renovation of regulated asbestos containing material.

9. As per a letter received by the Department on December 22, 1992, ownership of the Kerley Enterprises facility was transferred to Jupiter as of December 31, 1992. ConocoPhillips assumed responsibility for any and all air pollutant emissions from any sources covered by the most current state air quality permit, including those owned and constructed by Kerley Enterprises, Inc. ConocoPhillips is responsible for full compliance with all the following permit conditions, including those associated with the operation of the Jupiter sulfur recovery facility. The operational control of emissions at the Jupiter facility and assumption of all responsibility for said emissions by ConocoPhillips is a material element of the Department's issuance of this permit.

10. All systems within the ConocoPhillips refinery and Jupiter sulfur recovery facility (modifications) shall be totally enclosed and controlled such that any pollutant generated does not vent to atmosphere, except as expressly allowed in this permit (ARM 17.8.749).

11. ConocoPhillips shall install and maintain the following burners:

a. The recycle hydrogen heater and fractionator feed heater shall be equipped with ULNB;

b. The 20.0-MMscfd hydrogen plant heater shall be equipped with LNB and FGR;

c. The Sulfur Recovery Unit (SRU) Incinerator (F-304) shall be equipped with LNB;

d. The coker heater shall be equipped with LNB;[1]

e. The PMA process heater (H-3201) shall be equipped with LNB with FGR;

f. Boilers B-7 and B-8 shall be equipped with ULNB; and

g. No.5 HDS Charge Heater, No.5 HDS Stabilizer Reboiler Heater, and No.2 $H_2$ Unit Reformer Heater, EPN-41, 42, and 43 respectively, shall be equipped with ULNB.

12. ConocoPhillips shall operate and maintain two CPI separator tanks with carbon-canister total-VOC controls to comply with 40 CFR Part 60, Subpart QQQ, and 40 CFR Part 61, Subpart FF, regulations. The CPI separators will be vented to two carbon canisters, in series, designed and operated to reduce VOC emissions by 95%, or greater, with no detectable emissions. This CPI separator system will replace the existing American Petroleum Institute (API) separator system.

13. ConocoPhillips shall comply with all applicable requirements of ARM 17.8.342, which reference 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Source Categories:

a. Subpart A, General Provisions, applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below:

b. Subpart R, National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations), shall apply to, but not be limited to, the bulk loading rack;

c. Subpart CC, National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries, shall apply to, but not be limited to, Miscellaneous Process Vents; Storage Vessels; Wastewater Streams; Equipment Leaks; and the Gasoline Loading Rack; and

d. Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, when effective, shall apply to, industrial, commercial, or industrial boiler or process heaters that are located at, or are part of a major source of Hazardous Air Pollutant (HAP) emissions.

ConocoPhillips shall review the regulation after promulgation and comply with all applicable requirements.

14. ConocoPhillips shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements as specified in 40 CFR Part 63 (ARM 17.8.342).

15. The bulk loading gasoline and distillates loading rack shall be operated and maintained as follows:

[1] The low $NO_X$ burners for the coker heater are a requirement of the coker Permit #2619 issued April 19, 1990.

a. ConocoPhillips' loading rack shall be equipped with a vapor collection system designed to collect the organic compound vapors displaced from cargo tanks during product loading (ARM 17.8.342);

b. ConocoPhillips' collected vapors shall be routed to the VCU at all times. In the event the VCU was inoperable, ConocoPhillips may continue to load only distillates, provided the Department is notified in accordance with the requirements of ARM 17.8.110 (ARM 17.8.752);

c. The vapor collection and liquid loading equipment shall be designed and operated to prevent gauge pressure in the gasoline cargo tank from exceeding 4,500 Pascals (Pa) (450 millimeters (mm) of water) during product loading. This level shall not be exceeded when measured by the procedures specified in the test methods and procedures in 40 CFR 60.503(d) (ARM 17.8.342);

d. No pressure vacuum vent in the permitted terminal's vapor collection system shall begin to open at a system pressure less than 4,500 Pa (450 mm of water) (ARM 17.8.342);

e. The vapor collection system shall be designed to prevent VOC vapors collected at one loading position from passing to another loading position (ARM 17.8.342);

f. Loading of liquid products into cargo tanks shall be limited to vapor-tight gasoline cargo tanks using the following procedures (ARM 17.8.342):

    i. ConocoPhillips shall obtain annual vapor tightness documentation described in the test methods and procedures in 40 CFR 63.425(e) for each gasoline cargo tank that is to be loaded at the loading rack;

    ii. ConocoPhillips shall require the cargo tank identification number to be recorded as each gasoline cargo tank is loaded at the terminal;

    iii. ConocoPhillips shall cross check each tank identification number obtained during product loading with the file of tank vapor tightness documentation within 2 weeks after the corresponding cargo tank is loaded;

    iv. ConocoPhillips shall notify the owner or operator of each non-vapor-tight cargo tank loaded at the loading rack within 3 weeks after the loading has occurred; and

    v. ConocoPhillips shall take the necessary steps to ensure that any non-vapor-tight cargo tank will not be reloaded at the loading rack until vapor tightness documentation for that cargo tank is obtained which documents that:

        a. The gasoline cargo tank meets the applicable test requirements in 40 CFR 63.425(e) of this permit; and

b. For each gasoline cargo tank failing the test requirements in 40 CFR 63.425(f) or (g), the gasoline cargo tank must either:

i. Before the repair work is performed on the cargo tank, meet the test requirements in 40 CFR 63.425 (g) or (h), or

ii. After repair work is performed on the cargo tank before or during the tests in 40 CFR 63.425 (g) or (h), subsequently passes, the annual certification test described in 40 CFR 63.425(e).

g. ConocoPhillips shall ensure that gasoline cargo tanks at the loading rack are loaded only into cargo tanks equipped with vapor collection equipment that is compatible with the terminal's vapor collection system (ARM 17.8.342);

h. ConocoPhillips shall ensure that the terminal and the cargo tank vapor recovery systems are connected during each loading of a gasoline cargo tank at the loading rack (ARM 17.8.342);

i. Loading of cargo tanks shall be restricted to the use of submerged fill and dedicated normal service (ARM 17.8.749);

j. ConocoPhillips shall install and continuously operate a thermocouple and an associated recorder, or an ultraviolet flame detector and relay system, which will render the load rack inoperable if a flame is not present at the VCU flare tip, or any other equivalent device to detect the presence of a flame (ARM 17.8.342 and ARM 17.8.752);

k. ConocoPhillips shall perform a monthly leak inspection of all equipment in gasoline service. The inspection must include, but is not limited to, all valves, flanges, pump seals, and open-ended lines. For purposes of this inspection, detection methods incorporating sight, sound, or smell are acceptable. Each piece of equipment shall be inspected during the loading of a gasoline cargo tank (ARM 17.8.342);

l. A logbook shall be used and shall be signed by the owner or operator at the completion of each inspection. A section of the log shall contain a list, summary description, or diagram(s) showing the location of all equipment in gasoline service at the facility (ARM 17.8.342);

m. Each detection of a liquid or vapor leak shall be recorded in the logbook. When a leak is detected, an initial attempt at repair shall be made as soon as practicable, but no later than 5 calendar days after the leak is detected. Repair or replacement of leaking equipment shall be completed within 15 calendar days after detection of each leak, except as provided in “n” below (ARM 17.8.342);

n. Delay of repair of leaking equipment will be allowed upon a demonstration to the Department that repairs within 15 days is not feasible. The owner or operator shall provide the reason(s) a delay is needed and the date by which each repair is expected to be completed (ARM 17.8.342); and

o. ConocoPhillips shall not allow gasoline to be handled in a manner that would result in vapor releases to the atmosphere for extended periods of time. Measures to be taken include, but are not limited to, the following:

i. Minimize gasoline spills;

ii. Clean up spills as expeditiously as practicable;

iii. Cover all open gasoline containers with a gasketed seal when not in use and;

iv. Minimize gasoline sent to open waste collection systems that collect and transport gasoline to reclamation and recycling devices, such as oil/water separators (ARM 17.8.342).

16. Jupiter shall vent off-gas from the ASD unit operation to the B304 sulfur boiler except during malfunction or maintenance conditions, when the off-gases would be vented to the SRU flare (ARM 17.8.749).

17. ConcocoPhillips shall comply with the provisions of 40 CFR Part 82, Subpart F, Recycling and Emission Reduction as applicable.

B. Emission Limitations

1. Total refinery and sulfur recovery facility emissions shall not exceed the following:

a. <u>SRU/ATS Main Stack</u>

i. $SO_2$ Emissions - 25.00 lb/hr (167 ppm, rolling 12-hour average corrected to 0% oxygen on a dry basis); 0.300 ton/day.

ii. $NO_X$ Emissions - 18.92 lb/hr, 454.0 lb/day, 82.85 ton/yr.

iii. Particulate matter with an aerodynamic diameter of 10 microns or less ($PM_{10}$) Emissions - 7.76 lb/hr, 186.3 lb/day, 34.00 ton/yr.

iv. Carbon Monoxide (CO) Emissions - 0.40 lb/hr, 1.76 ton/yr.

v. Ammonia - 13.36 lb/hr, 320.5 lb/day, 58.5 ton/yr.

vi. Opacity - 20% averaged over any 6 consecutive minutes.

b. <u>SRU Flare</u>[2]

i. $SO_2$ Emissions - 25.00 lb/hr, 0.300 ton/day.

ii. Particulate matter (PM) and CO emissions shall be kept to their negligible levels as indicated in the permit application.

[2] Emissions occur only during times that the ATS plant is not operating.

iii. $H_2S$ content of the flare fuel gas (and pilot gas) burned shall not exceed 0.10 grain/dscf.

iv. Opacity - 20% averaged over any 6 consecutive minutes.

c. Total $SO_2$ emissions from the SRU/ATS main stack plus the SRU flare shall not exceed 109.5 tons/year (rolling 12-month average).

d. FCCU Stack

i. $SO_2$ Emissions - 328.8 lb/hr, rolling 24-hour average; 3.945 ton/day; 1440 ton/yr.

ii. CO Emissions – 150 ppmvd at 0% $O_2$ based on a rolling 365-day average basis. Compliance shall be demonstrated with the CO CEMS (ConocoPhillips Consent Decree, paragraph 50).

iii. CO Emissions – 500 ppmvd at 0% $O_2$ based on a one-hour average emission limit. Compliance shall be demonstrated with the CO CEMS (ConocoPhillips Consent Decree, paragraph 49).

iv. Opacity – not to exceed 20% averaged over 6 consecutive minutes. All opacity CEMS data associated with the monthly sandblasting operations shall be reported in the soot-blowing section of the monthly CEMS performance report.

e. Refinery Fuel Gas Heaters/Furnaces

i. $SO_2$ Emissions: 614 lb/day, rolling 24-hour average; and 45.5 ton/yr, rolling 12-month average (fuel gas combustion).

ii. $H_2S$ content of fuel gas burned shall not exceed 0.10 grain/dscf, rolling 3-hr average. Reference Section II.D.3.e.

iii. $H_2S$ content of fuel gas burned in:

Emission point 35, H-9401, the No. 1 $H_2$ Reformer Heater;
Emission point 7, H-10, the No. 2 HDS;
Emission point 8, H-11, the Debutanizer Reboiler, No. HDS;
Emission point 9, H-12, the Main Frac. Reboiler No. 2 HDS;
Emission point 10, H-13, the No. 2 Reformer;
Emission point 11, H-14, the No. 2 Reformer;
Emission point 13, H-16, the Stabilizer Reboiler, Sat Gas; and;
Emission point 20, H-23, the No.2 Reformer;
shall not exceed 0.073 grain/dscf rolling 3-hr average (116.5 ppmv $H_2S$) (ARM 17.8.749).

iv. Opacity from the 22 Refinery Fuel Gas Heaters/Furnaces shall not exceed 40% averaged over any 6 consecutive minutes, except as required in Section II.B.1.h.vi.

v. Opacity from the No.5 HDS Charge Heater, No.5 HDS Stabilizer Reboiler Heater, and No.2 $H_2$ Unit Reformer Heater shall not exceed 20% averaged over 6 consecutive minutes.

vi. $H_2S$ content of fuel gas burned in the No.5 HDS Charge Heater, No.5 HDS Stabilizer Reboiler Heater, and No.2 $H_2$ Unit Reformer Heater shall not exceed 0.073 grain/dscf (116.5 ppmv $H_2S$) (ARM 17.8.749).

vii. $NO_X$ emissions from the No.5 HDS Charge Heater shall not exceed 0.03 lb/MMBtu (ARM 17.8.752).

viii. CO emissions from the No.5 HDS Charge Heater shall not exceed 0.061 lb/MMBtu (ARM 17.8.749).

ix. $NO_X$ emissions from the No.5 HDS Stabilizer Reboiler Heater shall not exceed 0.03 lb/MMBtu (ARM 17.8.752).

x. CO emissions from the No.5 HDS Stabilizer Reboiler Heater shall not exceed 0.061 lb/MMBtu (ARM 17.8.749).

xi. $NO_X$ emissions from the No.2 $H_2$ Unit Reformer Heater shall not exceed 0.03 lb/MMBtu. The Pressure Swing Adsorption (PSA) purge gas used as heater fuel shall be sulfur free (ARM 17.8.752).

xii. CO emissions from the No.2 $H_2$ Unit Reformer Heater shall not exceed 0.061 lb/MMBtu. The Pressure Swing Adsorption (PSA) purge gas used as heater fuel shall be sulfur free (ARM 17.8.749).

xiii. The total $NO_X$ emissions from the No.5 HDS Charge Heater, the No.5 HDS Stabilizer Reboiler Heater, and the No.2 $H_2$ Unit Reformer Heater shall not exceed 7.35 lb/hr and 32.19 tons/year.

f. Main Boilerhouse Stack

i. $SO_2$ Emissions - 321.4 lb/hr, rolling 24-hour average; 3.857 ton/day; 1407.8 ton/yr (fuel oil and fuel gas combustion).

ii. $SO_2$ Emissions – 300 ton/yr based on a rolling 365-day average as determined by the existing $SO_2$ CEMS or replacement $SO_2$ CEMS subsequently installed and certified (ConocoPhillips Consent Decree, paragraph 71).

iii. $H_2S$ content of fuel gas burned shall not exceed 0.10 grain/dscf, rolling 3-hr average.

iv. Opacity - 40% averaged over any 6 consecutive minutes.

v. $NO_x$ emissions from boilers B-7 and B-8 shall each not exceed 0.03 lb/MMBtu fired on RFG or 24.05 ton/yr based on a rolling 365-day average. Compliance with the limits shall be monitored with the $NO_X$ and $O_2$ CEMS subsequently installed and certified (ARM 17.8.752).

vi. CO emissions from boilers B-7 and B-8 shall each not exceed 0.04 lb/MMBtu fired on RFG (ARM 17.8.752).

vii. VOC Emissions from boilers B-7 and B-8 shall each not exceed 4.32 tons/rolling 12-calendar month total (ARM 17.8.752).

g. Refinery Flare Stack

i. $H_2S$ in the fuel gas burned shall not exceed 0.10 grain/dscf, rolling 3-hr average.

ii. $SO_2$ emission increases, due to upset conditions or discontinuance of the SRU, shall be offset by an equivalent rate from any other sources covered by this permit.

h. Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, and Hydrogen Plant Heater

i. $NO_X$ emissions from the Hydrogen Plant heater shall not exceed 0.03 lb/MMBtu (ARM 17.8.752).

ii. $NO_X$ emissions from the Coker Heater shall not exceed 0.08 lb/MMBtu and 7.38 lb/hr (ARM 17.8.752).

iii. $NO_X$ emissions from the Recycle Hydrogen Heater shall not exceed 0.03 lb/MMBtu (ARM 17.8.752).

iv. $NO_X$ emissions from the Fractionator Feed Heater shall not exceed 0.03 lb/MMBtu (ARM 17.8.752).

v. The total $NO_X$ emissions from the Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, and Hydrogen Plant Heater shall not exceed 13.54 lb/hr and 58.95 tons/year.

vi. Opacity from the Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, and Hydrogen Plant Heater shall not exceed 20% averaged over any 6 consecutive minutes.

i. PMA Process Heater Stack

i. $NO_X$ emissions shall not exceed 80 lb/MMscf or 0.76 lb/hr (ARM 17.8.752).

ii. The PMA Process Heater shall be fired on purchased natural gas only and shall not be fired on RFG.

iii. Opacity - 20% averaged over any 6 consecutive minutes.

iv. Heater stack shall be 50 feet in height above grade, when the PMA Process Heater is operating.

j. PMA Storage Tank Vent

Opacity shall not exceed 0%, except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown clear (40 CFR 60.472(c)).

k. Total $SO_2$ emissions for refinery and sulfur recovery facilities shall not exceed the limit of 3103 ton/yr (Sections II.B.1.a - j). In addition, where applicable, all other federal emission limitations shall be met.

2. All access roads shall use either paving or chemical dust suppression as appropriate to limit excessive fugitive dust, with water as a back-up measure, to maintain compliance with ARM 17.8.308 and the 20% opacity limitation. ConocoPhillips shall use reasonable precautions during construction, and earth-moving activities shall use reasonable precautions to limit excessive fugitive dust and to mitigate impacts to nearby residential and commercial places.

3. Emissions from the loading of gasoline and distillates at the loading rack shall be limited to the following:

a. The total VOC emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 milligrams per liter (mg/L) of gasoline loaded (ARM 17.8.342 and ARM 17.8.752).

b. The total CO emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 mg/L of gasoline loaded (ARM 17.8.752).

c. The total $NO_X$ emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 4.0 mg/L of gasoline loaded (ARM 17.8.752).

d. ConocoPhillips shall not cause or authorize to be discharged into the atmosphere from the enclosed VCU:

i. Any visible emissions that exhibit an opacity of 10% or greater (ARM 17.8.749); and

ii. Any particulate emissions in excess of 0.10 gr/dscf corrected to 12% $CO_2$ (ARM 17.8.749).

4. ConocoPhillips shall operate and maintain the Saturate Gas Plant according to the Leak Detection and Repair (LDAR) program. ConocoPhillips shall monitor and maintain all pumps, shutoff valves, relief valves, and other piping and valves associated with the Saturate Gas Plant, as described in 40 CFR 60.482-1 through 60.482-10. Records of monitoring and maintenance shall be maintained on site for a minimum of 2 years (ARM 17.8.342 and ARM 17.8.752).

5. ConocoPhillips shall not burn fuel oil in any of its heaters (ARM 17.8.749).

6. ConocoPhillips shall operate and maintain all new (associated with the Low Sulfur Gasoline (LSG) project) fugitive component VOC emissions in the No.2 HDS Unit, the Gas Oil Hydrodesulfurizer (GOHDS) Unit, and the Tank Farm (including those fugitive emissions associated with the LSG tank) according to the LDAR program (ARM 17.8.342; ARM 17.8.752; and 40 CFR 63, Subpart

CC).

C. Testing Requirements - NSPS and NESHAP

1. ConocoPhillips shall meet the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR Part 60, NSPS, Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units. This shall apply to all affected boilers at the facility, which were constructed after June 19, 1984, are larger than 100 MMBtu/hr, and combust fossil fuel.

2. ConocoPhillips shall meet the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR Part 60, NSPS, Subpart J, Standards of Performance for Petroleum Refineries. This shall apply to, but not be limited to, all of the heaters and boilers at the ConocoPhillips refinery and the Claus units at the Jupiter sulfur recovery facility and any other applicable equipment.

3. ConocoPhillips shall meet the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR Part 60, NSPS, Subpart Ka, Standards of Performance for Volatile Organic Liquid Storage Vessels. This shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after May 18, 1978, and prior to July 23, 1984. These requirements shall be as specified in 40 CFR 60.110a through 60.115a. The affected tanks include, but are not limited to, the following:

   <u>Tank Number</u>
   #100-Ka*
   #101-Ka*
   #102-Ka
   #104-Ka*

   * Currently exempt from all emission control provisions due to vapor pressure of materials stored.

4. ConocoPhillips shall meet the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR Part 60, NSPS, Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels. This shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984. The affected tanks include, but are not limited to, the following:

   <u>Tank Number</u>
   #36-Kb
   #72-Kb
   #107-Kb*
   #110-Kb
   #162-Kb*
   #T-3201*
   #T-4523
   No.5 HDS Feed storage tank

   * Currently exempt from all emission control provisions due to vapor pressure of materials stored.

a. These requirements shall be as specified in 60.112b, 60.113b, 60.114b, 60.115b, 60.116b, and 60.117b.

b. ConocoPhillips shall keep copies of all reports and records required by 40 CFR Part 60.115b for at least 2 years and shall make those copies available for inspection by Department personnel at the location of the permitted source.

5. ConocoPhillips shall meet the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR Part 60, NSPS, Subpart GGG, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries. This shall apply to, but not be limited to, the delayed coker unit, cryogenic unit, hydrogen membrane unit, gasoline merox unit, crude vacuum unit, gas oil hydrotreater unit (consisting of a reaction section, fractionation section, and an amine treating section), 20.0-MMscfd hydrogen plant feed system, Alkylation Unit Butane Defluorinator Project (consisting of heat exchangers X-453, X-223, X-450, X-451, X-452; pump P-646; and vessels D-130, D-359, D-360), PMA process unit, Alkylation Unit Depropanizer Project, fugitive components associated with boilers B-7 and B-8, the fugitive components associated with the new No.2 $H_2$ Unit and the new No.5 HDS Unit, and any other applicable equipment constructed or modified after January 4, 1983.

6. ConocoPhillips shall meet the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR Part 60, NSPS, Subpart QQQ, Standards of Performance for Volatile Organic Compound Emissions from Petroleum Refinery Wastewater Systems. This shall apply to, but not be limited to, the coker unit drain system, desalter wastewater break tanks, CPI separators, gas oil hydrotreater, 20.0-MMscfd hydrogen plant, C-23 compressor station, Alkylation Unit Butane Defluorinator Project, Alkylation Unit Depropanizer Project, the new individual drain system in the No.2 $H_2$ Unit and the new No.5 HDS Unit, and any other applicable equipment.

7. ConocoPhillips shall meet the requirements of all testing and procedures of ARM 17.8.342, which reference 40 CFR Part 63, MACT, Subpart R, NESHAPs for Gasoline Distribution Terminals. This shall apply to, but not be limited to, the bulk gasoline and distillate loading rack, the vapor processing system, and all gasoline equipment.

8. ConocoPhillips shall meet the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR Part 63, Subpart CC, NESHAPs for Petroleum Refineries, shall apply to, but not be limited to, Miscellaneous Process Vents; Storage Vessels; Wastewater Streams; Equipment Leaks; and the Gasoline Loading Rack.

9. After promulgation, ConocoPhillips shall meet the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR Part 63, Subpart DDDDD, NESHAPs for Industrial, Commercial, and Institutional Boilers and Process Heaters. The NESHAP shall apply to, industrial, commercial, or industrial boiler or process heaters that are located at, or are part of a major source of HAP emissions.

D. Emission Testing and Reporting

1. ConocoPhillips shall test boilers B-7 and B-8 for $NO_x$ and CO, concurrently, and demonstrate compliance with the $NO_x$ and CO emission limits contained in Sections II.B.1.f.v and vi. The compliance source testing shall be conducted within 180 days of initial start-up of each boiler. After the initial source test, additional testing shall be conducted on an every 5-year basis or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and 17.8.749).

2. ConocoPhillips shall report to the Department any time in which the sour water stripper stream from the refinery is diverted away from the sulfur recovery facility. Said excess emission reports shall include the period of diversion, estimate of lost raw materials ($H_2S$ and ammonia ($NH_3$)), and resultant pollutant emissions, including circumstances explaining the diversion of this stream. Said excess emission reports shall discuss what corrective actions will be taken to prevent recurrences of the situation and what caused the upset. These reports shall address, at a minimum, the requirements of ARM 17.8.110.

3. ConocoPhillips shall install and operate the following CEMS/continuous emission rate monitors (CERMs):

   a. <u>SRU/ATS Stack</u>

      i. $SO_2$
      ii. Oxygen
      iii. Volumetric flow rate

   b. <u>FCCU Stack</u>

      i. $SO_2$
      ii. Volumetric flow rate
      iii. Opacity

   c. <u>Main Boiler Stack</u>

      i. $SO_2$
      ii. Volumetric flow rate

      Said monitors shall comply with all applicable provisions of 40 CFR Part 60, Subpart J, 60.100-106, and Appendix B, Performance Specifications 1, 2, 3 and 6.

   d. <u>All Affected Boilers Including B-7 and B-8</u>

      i. $NO_X$
      ii. $O_2$

   Said monitors shall comply with all applicable provisions of 40 CFR Part 60, Subpart Db.

e. Main Boiler and (22) RFG Heaters/Furnaces

Continuous $H_2S$ RFG System Monitoring - Continuous refinery fuel gas monitoring system for $H_2S$ shall meet all performance specifications, methods and procedures. $H_2S$ concentration monitor on the fuel gas system shall meet 40 CFR Part 60, Appendix B, Performance Specification 7.

f. Flare(s) (Refinery and SRU Facility) Stack

i. Flow rate metering from upset or malfunctioning process units that are directed to the flare shall use approved standards, methods, accounting procedures, and engineering data.

ii. Recordkeeping requirements (see Sections II.E.2 - 3).

4. Enforcement of Section II.B.1 requirements, where applicable, shall be determined by utilizing data taken from CEMS and other Department-approved sampling methods. However, opacity compliance may also be determined via EPA Reference Method 9 by a certified observer or monitor.

a. The above does not relieve ConocoPhillips from meeting any applicable requirements of 40 CFR Part 60, Appendices A and B, or other stack testing that may be required by the Department.

b. Other stack testing may include, but is not limited to, the following air pollutants: $SO_2$, $NO_X$, $NH_3$, CO, PM, $PM_{10}$, and VOC.

c. Reporting requirements shall be consistent with 40 CFR Part 60, or as specified by the Department.

d. All gaseous continuous emission monitors shall be required to comply with the quality assurance/quality control procedures in 40 CFR Part 60, Appendix F. Said CEMS shall be required to be maintained such that they are available and operating at least 90% of the source operating time during any reporting period (quarterly).

e. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, ConocoPhillips shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated. The Department shall approve such contingency plans.

5. Compliance testing and continuous monitor certification shall be as specified in 40 CFR Part 60, Appendices A and B. Test methods and procedures, where there is more than one option for any given pollutant, shall be worked out with the Department prior to commencement of testing.

6. ConocoPhillips shall conduct compliance testing and continuous monitor certification as specified in 40 CFR Part 60, Appendices A and B, within 180 days of initial start up of the affected facility.

7. ConocoPhillips shall conduct compliance source tests on the SRU Main stack for $PM_{10}$ and $NO_X$ to determine compliance with the applicable emission standards in Section II.B.1.a in 1998, 2002, and every 5 years thereafter.

8. ConocoPhillips shall conduct compliance source tests on the Coker Heater for $NO_X$ to determine compliance with the emission limitations in Section II.B.1.h.ii within 180 days of issuance of Permit #2619-09.

9. The bulk loading rack VCU shall be initially tested for total organic compounds, and compliance demonstrated with the emission limitation contained in Section II.B.3.a within 180 days of initial start up and every 5 years after the initial test. ConocoPhillips shall conduct the test methods and procedures as specified in 40 CFR 63.425, Subpart R (ARM 17.8.105 and 17.8.342).

10. The bulk loading rack VCU shall be initially tested for CO and $NO_X$, and compliance demonstrated with the emission limitations contained in Section II.B.3.b and c within 180 days of initial start up (ARM 17.8.105).

11. ConocoPhillips shall conduct compliance source tests on the No.5 HDS Reboiler Heater for $NO_X$ and CO to determine compliance with the emission limitations in Sections II.B.1.e.ix and II.B.1.e.x within 180 days of initial startup (ARM 17.8.105).

12. ConocoPhillips shall conduct compliance source tests on the No.2 $H_2$ Reformer Heater for $NO_X$ and CO to determine compliance with the emission limitations in Sections II.B.1.e.xi and II.B.1.xii within 180 days of initial startup (ARM 17.8.105).

13. All compliance source tests shall be conducted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

14. The Department may require further testing (ARM 17.8.105).

E. Monitoring and Reporting

1. ConocoPhillips shall install, operate and maintain the applicable CEMS/CERMS listed in Sections II.D.3.a, b, c, and d. Emission monitoring shall be subject to 40 CFR Part 60, Subpart J, Appendix B (Performance Specifications 1, 2, 3, 6 and 7) and Appendix F (Quality Assurance/Quality Control) provisions. Any stack testing requirements that may be required (in Section II.D.4) shall be conducted according to 40 CFR Part 60, Appendix A and ARM 17.8.105, Testing Requirements provisions.

2. ConocoPhillips shall provide monthly emission reports from said emission rate monitors. Emission reporting for $SO_2$ from all point source locations shall consist of 24-hour calendar-day totals per calendar month. The monthly report shall also include the following:

   a. Source or unit operating time during the reporting period.

   b. Monitoring down time, which occurred during the reporting period.

c. A summary of excess emissions for each pollutant and averaging period identified in Section II.B.1.

d. Emission estimates for $NO_x$ and $NH_3$ from material balance, engineering calculation data, and any emission testing.

e. Reasons for any emissions in excess of those specifically allowed in Section II.B.1 with mitigative measures utilized and corrective actions taken to prevent a recurrence of the upset situation.

ConocoPhillips shall submit monthly emission reports within 30 days of the end of each calendar month.

3. ConocoPhillips shall keep the Department apprised of the status of construction, dates of performance tests, and continuous compliance status for each emission point and pollutant. Specifically, the following report and recordkeeping shall be submitted in writing:

a. Notification of date of construction commencement, cessation of construction, restarts of construction, startups, initial emission tests, monitor certification tests, etc.

b. Submittal for review by the Department of the emissions testing plan, results of initial compliance tests, continuous emission monitor certification tests, continuous emission monitoring and continuous emissions rate monitoring quality assurance/quality control plans, and excess emissions report within the 180-day shakedown period.

c. Copies of said monthly emissions report, excess emissions, and all other such items mentioned in Section II.E.3.a and b above shall be submitted to both the Billings Regional Office and the Helena office of the Department.

d. Monitoring data shall be maintained for a minimum of 5 years at the ConocoPhillips Refinery and Jupiter sulfur recovery facilities.

e. All data and records that are required to be maintained must be made available upon request by representatives of the EPA.

4. ConocoPhillips shall install, operate and maintain the applicable CEMS/CERMS listed in Section II.D.3.d. Emission monitoring shall be subject to 40 CFR Part 60, Subpart Db. Any stack testing requirements that may be required (in Section II.D.1) shall be conducted according to 40 CFR Part 60, Appendix A and ARM 17.8.105, Testing Requirements provisions.

F. Additional Reporting Requirements - NSPS, NESHAP, and MACT:

1. ConocoPhillips shall keep records and furnish reports to the Department as required by 40 CFR Part 60, NSPS, Subpart Kb. These reports shall include information described in 40 CFR 60.115b.

2. ConocoPhillips shall provide copies to the Department, upon the Department's request, of any records of tank testing results required by 40 CFR 60.113b and monitoring of operations required by 40 CFR 60.116b. Records will be available

according to the time period requirements as described in 40 CFR 60.115b and 40 CFR 60.116b.

3. ConocoPhillips shall conduct all applicable recordkeeping and reporting requirements in accordance with 40 CFR Part 60, Subpart QQQ.

4. ConocoPhillips shall provide the Department copies of testing results, monitoring operations, recordkeeping and report results as specified under 40 CFR Part 60, Subpart QQQ, Sections 60.693-2, 60.696, 60.697, and 60.698.

5. ConocoPhillips shall monitor the exhaust vent stream from the wastewater CPI separators carbon-adsorption system (T-169 & T-170 carbon canisters) on a regular schedule according to the requirements contained in 40 CFR Part 60, Subpart QQQ, Section 60.695(a)(3)(ii) and 40 CFR Part 61 Subpart FF, Section 61.354(d). The existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated. The device shall be monitored at intervals not to exceed 14.4 hours, when the wastewater treatment is operational. The time period may be revised by the Department in the event that the carbon absorption system is upgraded or physically altered.

6. ConocoPhillips shall supply the Department's Permitting and Compliance Division with the reports as required by 40 CFR Part 61, NESHAP Subpart FF, Benzene Waste Operations.

7. ConocoPhillips shall keep all records and furnish all reports to the Department as required by 40 CFR Part 63, Subpart R, NESHAPs for Gasoline Distribution Facilities. These reports shall include information described in 40 CFR 63.424, 63.427, and 63.428.

8. ConocoPhillips shall keep all records and furnish all reports to the Department as required by 40 CFR Part 63, Subpart CC, NESHAPs for Petroleum Refineries.

9. ConocoPhillips shall keep all records and furnish all reports to the Department as required by 40 CFR Part 63, Subpart DDDDD, NESHAPs for Industrial, Commercial, and Institutional Boilers and Process Heaters, when effective.

G. Operational Reporting Requirements

1. ConocoPhillips shall supply the Department with annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the most recent emission inventory report and sources identified in this permit.

   Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units required by the Department. This information is required for the annual emission inventory and to verify compliance with permit limitations. The information supplied shall include the following (ARM 17.8.505):

a. Sources - ConocoPhillips

| Emission Point | Source | Consumption |
|---|---|---|
| 1 | Four (4) Boilers | MMscf of gas, %$H_2S$ gal of fuel oil, %S |
| 2 | Heater #1 | MMscf of gas, %$H_2S$ |
| 3 | Heater #2 | MMscf of gas, %$H_2S$ |
| 4 | Heater #4 | MMscf of gas, %$H_2S$ |
| 5 | Heater #5 | MMscf of gas, %$H_2S$ |
| 6 | Coker Heater | MMscf of gas, %$H_2S$ |
| 7 | Heater #10 | MMscf of gas, %$H_2S$ |
| 8 | Heater #11 | MMscf of gas, %$H_2S$ |
| 9 | Heater #12 | MMscf of gas, %$H_2S$ |
| 10 | Heater #13 | MMscf of gas, %$H_2S$ |
| 11 | Heater #14 | MMscf of gas, %$H_2S$ |
| 12 | Heater #15 | MMscf of gas, %$H_2S$ |
| 13 | Heater #16 | MMscf of gas, %$H_2S$ |
| 14 | Heater #17 | MMscf of gas, %$H_2S$ |
| 15 | Heater #18 | MMscf of gas, %$H_2S$ |
| 16 | Heater #19 | MMscf of gas, %$H_2S$ |
| 17 | Heater #20 | MMscf of gas, %$H_2S$ |
| 18 | Heater #21 | MMscf of gas, %$H_2S$ |
| 19 | Heater #22 | MMscf of gas, %$H_2S$ |
| 20 | Heater #23 | MMscf of gas, %$H_2S$ |
| 21 | Heater #24 | MMscf of gas, %$H_2S$ |
| 22 | FCC Unit | Tons of $SO_2$/yr |
| 23 | Flare | Tons of $SO_2$/yr |
| 24 | Storage Tanks T | ons VOC losses/yr |
| 25 | Bulk Loading Gasoline | Gallons of gasoline throughput<br>Gallons of distillate throughput |
| 26 | Fugitive VOC Emissions: | |

i. The number of the following fugitive VOC emission sources in service subject to 40 CFR Part 60, Subpart GGG.

a. Gas valves
b. Light liquid valves
c. Heavy liquid valves
d. Hydrogen valves
e. Open-end valves
f. Flanges
g. Pump seals/light liquid
h. Pump seals/heavy liquid
i. Oil/water separators Process drains

ii. The number of the following fugitive VOC emission sources in service not subject to 40 CFR Part 60, Subpart GGG.

a. Valves
b. Flanges
c. Pump seals
d. Compressor seals
e. Relief valves
f. Oil/water separators

| | | |
|---|---|---|
| 27 | CPI separator tanks | Gallons of wastewater throughput |
| 28 | Recycle hydrogen heater | MMscf of gas, %$H_2S$ |
| 29 | Fractionator feed heater | MMscf of gas, %$H_2S$ |
| 30 | 20.0-MMscfd hydrogen plant SMR heater | MMscf of natural gas<br>MMscf of PSA gas |
| 31 | PMA process heater | MMscf of natural gas |
| 32 | Saturate Gas Plant | Monitoring and maintenance records |
| 41 | No.5 HDS Charge Heater | MMscf of gas, %$H_2S$ |
| 42 | No.5 HDS Stabilizer Reboiler Heater | MMscf of gas, %$H_2S$ |
| 43 | No.2 $H_2$ Unit Reformer Heater | MMscf of gas, %$H_2S$<br>MMscf of PSA gas |

b. Sources - Jupiter

| Emission Point | Source | Consumption |
|---|---|---|
| 1 | Main ATS Stack | |
| | a. ATS unit | Tons of product produced |
| | b. Elemental sulfur unit | Tons of product produced |
| 2 | Jupiter Flare - | |
| | a. Ammonium sulfide unit | Tons of product produced |

2. For reporting purposes, the equipment should be identified using the emission point numbers specified.

3. ConocoPhillips shall notify the Department of any construction or improvement project conducted pursuant to ARM 17.8.745, that would include a change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

H. Notification

ConocoPhillips shall provide the Department with written notification of the following dates within the specified time periods.

1. Pretest information forms must be completed and received by the Department no later than 25 working days prior to any proposed test date, according to the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

2. The Department must be notified of any proposed test date 10 working days before that date, according to the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

3. ConocoPhillips shall notify the Department of any construction or improvement project conducted pursuant to ARM 17.8.745(1) that would include a change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location, or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted to the Department, in writing, 10 days prior to startup or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

4. ConocoPhillips shall notify the Department of the date of construction commencement for the low sulfur gas project no later than 30 days after construction commencement (ARM 17.8.340, ARM 17.8.749, and 40 CFR 60.7 for NSPS-applicable sources).

5. ConocoPhillips shall notify the Department of the actual start-up date of the low sulfur gas project to be postmarked within 15 days after the actual start-up date (ARM 17.8.340, ARM 17.8.749, and 40 CFR 60.7 for NSPS-applicable sources).

6. ConocoPhillips shall provide written notification to the Department of the date of construction commencement for the boiler replacement project no later than 30 days after construction commencement (ARM 17.8.340, ARM 17.8.749, and 40 CFR 60.7 for NSPS-applicable sources).

7. ConocoPhillips shall provide written notification to the Department of the actual completion date of the boiler replacement project. The notice shall be postmarked no more than 15 days after the actual completion date (ARM 17.8.340, ARM 17.8.749, and 40 CFR 60.7 for NSPS-applicable sources).

8. ConocoPhillips shall provide written notification to the Department of the date of construction commencement for the ULSD project no later than 30 days after construction commencement (ARM 17.8.340, ARM 17.8.749, and 40 CFR 60.7 for NSPS-applicable sources).

9. ConocoPhillips shall provide written notification to the Department of the actual completion date of the ULSD project. The notice shall be postmarked no more than 15 days after the actual completion date (ARM 17.8.340, ARM 17.8.749, and 40 CFR 60.7 for NSPS-applicable sources).

SECTION III: General Conditions

A. Inspection - The recipient shall allow the Department's representatives access to the source at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (CEMS, CERMS) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

B. Waiver - The permit and all the terms, conditions, and matters stated herein shall be deemed accepted if the recipient fails to appeal as indicated below.

C. Compliance with Statutes and Regulations - Nothing in this permit shall be construed as relieving the permittee of the responsibility for complying with any applicable federal or Montana statute, rule or standard, except as specifically provided in ARM 17.8.740, *et seq*. (ARM 17.8.756)

D. Enforcement - Violations of limitations, conditions and requirements contained herein may constitute grounds for permit revocation, penalties or other enforcement as specified in Section 75-2-401 *et seq.*, MCA.

E. Appeals - Any person or persons who are jointly or severally adversely affected by the Department's decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The Department's decision on the application is not final unless 15 days have elapsed and there is no request for a hearing under this section. The filing of a request for a hearing postpones the effective date of the Department's decision until the conclusion of the hearing and issuance of a final decision by the Board.

F. Permit Inspection - As required by ARM 17.8.755, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by Department personnel at the location of the permitted source.

G. Construction Commencement - Construction must begin within 3 years of permit issuance and proceed with due diligence until the project is completed or the permit shall be revoked.

H. Permit Fees - Pursuant to Section 75-2-220, MCA, as amended by the 1991 Legislature, failure to pay by the permittee of an annual operation fee may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

PERMIT ANALYSIS
ConocoPhillips Company, Billings Refinery
Permit #2619-19

I. Introduction/Process Description

A. Source Description

The ConocoPhillips Company, Billings Refinery (ConocoPhillips) is located at 401 South 23rd Street, Billings, Montana, in the NW¼ of Section 2, Township 1 South, Range 26 East, in Yellowstone County. The refinery property is adjacent to the City of Billings and is next to Interstate 90 and the Yellowstone River. Residential properties exist on the west side of the refinery and the United States Postal Service has an office located on the south side of the property.

The refinery processes 50,000 barrels per day of crude oil and produces a wide range of petroleum products, including propane, gasoline, kerosene/jet fuel, diesel, and petroleum coke. ConocoPhillips has received several air quality permits throughout the past years for various pieces of equipment and operations. All previously permitted equipment, limitations, conditions, and reporting requirements stated in Permits #1719, #2565, #2669, #2619, and #2619A were included in Permit #2619-02.

B. Permit History

On October 29, 1982, Conoco Inc. (Conoco) received an air quality permit for an emergency flare stack to be equipped and operated with steam injection. This application was given **Permit #1719**.

On June 2, 1989, Conoco received an air quality permit to convert an existing 5000-barrel cone roof tank (#49) to an internal floating roof with double seals. This conversion was necessary in order to switch service from diesel to aviation gasoline storage. The application was given **Permit #2565**.

On January 29, 1991, Conoco received an air quality permit to construct and operate two 2000-barrel desalter wastewater break tanks equipped with external floating roofs and double-rim seals. The new tanks were to augment the refinery's ability to control fugitive Volatile Organic Compounds (VOC) emissions and enhance recovery of oily water from the existing wastewater treatment system. The application was given **Permit #2669**.

On April 19, 1990, Conoco received an air quality permit to construct new equipment and modify existing equipment at the refinery and to construct a sulfur recovery facility, operated by Kerley Enterprises under the control of Conoco, as part of the overall Conoco project. The application was given **Permit #2619**.

Conoco was permitted to construct a new 13,000-barrels-per-stream-day delayed petroleum coker unit, cryogenic gas plant, gasoline treating unit, and hydrogen system additions. Also, modifications to the existing crude and vacuum distillation units, hydrodesulfurization units, amine treating units and wastewater treatment system were permitted.

Conoco was also permitted to construct a sulfur recovery facility (SRU)/ammonium thiosulfate (ATS) to be operated by Kerley Enterprises. This facility is operated in conjunction with the new installations and modifications at the Conoco Refinery. This facility was permitted with the capability of utilizing 109.9 long tons per day of equivalent sulfur obtained from the Conoco Refinery for the manufacture of elemental sulfur and sulfur-containing fertilizer solutions (i.e., ATS).

On December 4, 1991, Conoco was issued **Permit #2619A** for the construction of a 1000-barrel hydrocarbon storage tank (T-162). The new tank stores recovered hydrocarbon product from the contaminated groundwater aquifer beneath the Conoco Refinery. Over the years, surface discharges at the refinery contaminated the groundwater with oily hydrocarbon products. The purpose of this project was to recover hydrocarbon product (oil) from the groundwater aquifer beneath the refinery. The hydrocarbon product (oil) is pumped out of a cone of depression within the contaminated groundwater aquifer. Groundwater, less the recovered hydrocarbon product, is returned to the aquifer. The application addressed the increase in VOC emissions from the storage of recovered hydrocarbon product.

On March 5, 1993, Conoco was issued **Permit #2619-02** for the construction and operation of a 5.0-MMscf-per-day hydrogen plant and to replace their existing American Petroleum Institute (API) separator system with a corrugated plate interceptor (CPI) separator system. This permit was an alteration to Conoco's existing Permit #2619 and included all previously permitted equipment, limitations, conditions, and reporting requirements stated in Permits #1719, #2565, #2669, #2619, and #2619A.

The natural gas feedstock to the new hydrogen plant produces 99.9% pure hydrogen. This hydrogen and hydrogen from the existing catalytic reformers is routed to the refinery hydrotreaters to reduce fuel product sulfur content. The Hydrogen sulfide ($H_2S$) produced is routed to the Jupiter SRU/ATS, operated by Kerley Enterprises, which produces sulfur and fertilizer products.

The two new CPI separator tanks with carbon canister total VOC controls were constructed to comply with 40 Code of Federal Regulations (CFR) Part 60, Subpart QQQ, and 40 CFR Part 61, Subpart FF, regulations. The CPI separators were vented to two carbon canisters in series. Each carbon canister was designed and operated to reduce VOC emissions by 95% or greater, with no detectable emissions. This CPI separator system replaced the existing API separator system.

As per a letter received by the Department of Environmental Quality (Department), on December 22, 1992, ownership of the Kerley Enterprises facility was transferred to Jupiter Sulphur, Inc. as of December 31, 1992.

On September 14, 1993, Conoco was issued **Permit #2619-03** for the construction and operation of a gas oil hydrotreater and associated hydrogen plant at the Billings Refinery. The new hydrotreater desulfurizes a mixture of Fluid Catalytic Cracker (FCC) feed gas oils, which allows the FCC to produce low-sulfur gasoline. This low-sulfur gasoline was required by January 1, 1995, to satisfy Environmental Protection Agency's (EPA) gasoline sulfur provisions of the Federal 1990 Clean Air Act Amendments. Hydrogen requirements are met by the installation of a hydrogen plant, and sulfur recovery capacity was provided by installing additional elemental liquid sulfur production facilities at the Jupiter Sulphur, Inc. plant adjacent to the refinery.

The Gas Oil Hydrodesulfurizer (GOHDS) was designed to meet the primary objective of removing sulfur from the FCC feedstock. A combination of gas oils feed the Gas Oil

Hydrotreater. The gas oils are mixed with hydrogen, heated, and passed over a catalyst bed where desulfurization occurs. The gas oil is then fractionated into several products, cooled, and sent to storage. A steam-methane reforming hydrogen plant produces makeup hydrogen for the unit. Any unconsumed hydrogen is amine treated for hydrogen $H_2S$ removal and recycled.

The new project did not increase refinery capacity. The project did not constitute a major modification for purposes of the Prevention of Significant Deterioration (PSD) program since net emissions did not increase in significant amounts as defined by the Administrative Rules of Montana (ARM) 17.8.801(20)(a).

The additional fugitive VOC emissions from this project were calculated by totaling the fugitive sources on the process units. These sources included flanges, valves, relief valves, process drains, compressor seal degassing vents and accumulator vents and open-ended lines. The fugitive source tabulation was then used with actual refinery emission factors obtained from the Conoco Refinery in Ponca City, Oklahoma. Furthermore, it was intended that each non-control valve in VOC service would be repacked with graphite packing to Conoco standards before installation. All control valves for the GOHDS project would be Enviro-Seal valves or equivalent. The Enviro-Seal valves have a performance specification that exceeds the Subpart GGG standards. The VOC emissions will be validated by 40 CFR Part 60, Subpart GGG, emission monitoring.

The Jupiter Sulphur, Inc. Recovery Facility consists of three primary units: the existing ATS Plant, the existing ATS Unit and the new Claus Sulfur and Tail Gas Treating Units (TGTU). The addition of the new units increased the total sulfur recovery capacity of the facility from 110 to 170 LT/D (long tons per day) of sulfur.

The existing ATS plant consisted of a thermal Claus reaction-type boiler. The exit gas from this Claus boiler is incinerated in the ATS Unit. The sulfur dioxide ($SO_2$) from the incinerator is absorbed and converted to ammonium bisulfite (ABS). The ABS is then used to absorb and react with $H_2S$ to produce the ATS product. Up to 110 LT/D of sulfur can be processed by the ATS Plant to produce sulfur and ATS.

The Ammonium Sulfide Unit (ASD) consists of an absorption column, which absorbs the sulfur as $H_2S$ in the acid gas feed and reacts with ammonia ($NH_3$) and water. When the new Claus Sulfur Unit was added, the Sulfur Recovery Facility was modified to incinerate any off gas from this unit in the TGTU and ATS Plant. This eliminates off-gas flow to, and emissions from, the flare. Up to 110 LT/D of sulfur can be processed by the ASD to produce ammonium sulfide solution.

The proposed Claus Sulfur Unit consisted of a thermal Claus reaction furnace, followed by a waste heat boiler and three catalytic Claus reaction beds. The Claus tail gas is then incinerated before entering the TGTU. In this new unit, $SO_2$ from the incinerator was absorbed and converted to ABS. This ABS is then transferred to the ATS Unit for conversion to ATS. Up to 110 LT/D of sulfur can be processed by the new Claus Sulfur Unit to produce sulfur and ABS. The ABS from the TGTU is dilute, containing a significant amount of water that was generated from the Claus reaction. To prevent making a dilute ATS from this "weak" ABS, a new ATS Reactor was added to the ATS Unit. This ATS Reactor combines "weak" ABS, additional ABS, and sulfur to make a full-strength ATS solution.

An important feature of the Jupiter Sulphur, Inc. facility is its capability to process Conoco Inc.'s sour gases at all times. A maximum of 170 LT/D of sulfur is recovered and each of the three units has a capacity of 110 LT/D. If any one of the three is out of service, then the other two can easily handle the load. While the process has 100% redundancy, any two of the three units must be running to handle the design load. The process uses high-efficiency gas filters, which employ a water-flushed coalescer cartridge to reduce particulate, as well as sulfur compounds.

On November 11, 1993, Conoco was issued **Permit #2619-04** to construct and operate a new compressor station and associated equipment at the Billings Refinery. The C-23 compressor station project involved the recommissioning of an out-of-service compressor and associated equipment components having fugitive VOC emissions. The project also involved the installation of new equipment components having fugitive VOC emissions. The recommissioned compressor was originally installed in 1948. The compressor underwent some minor refurbishing, but did not trigger "reconstruction" as defined in 40 CFR 60.15.

The purpose of the C-23 compressor station project was to improve the economics of the refinery's wet gas (gas streams containing recoverable liquid products) processing through increased yields and more efficient operation in the refinery's large and small Crude Topping Units (CTUs) and the Alkylation Unit. The project also improved safety in the operations of the two CTUs, Alkylation Unit, and Gas Recovery Plant (GRP). As a result of this project, the vapor pressure of the alkylate product (produced by the Alkylation Unit) was lowered.

On February 2, 1994, Conoco was issued **Permit #2619-05** to construct and operate a butane defluorinator within the alkylation unit at the refinery. Installation of an alumina ($Al_2O_3$) bed defluorinator system was to remove residual hydrofluoric acid (HF) and organic fluorides from the butane stream produced by the Alkylation Unit. This reduced the fluorine level of the butane from ~ 500 ppmw to ~ 1 ppmw, which allows the butane to be recycled back to the refinery's Butamer Unit for conversion into isobutane. Refer to the permit application for a more thorough description of the process and proposed changes.

The Alkylation Unit Butane Defluorinator Project resulted in: (1) changes in operation of the alkylate stabilization train of the Alkylation Unit to yield defluorinated butane instead of fluorinated and lower vapor pressure alkylate products; (2) changes in operation of the refinery's gasoline blending to restructure butane blending and lower the vapor pressure of the gasoline pool; (3) minimized butane sales; (4) minimized butane burning as refinery fuel gas; and (5) economized gasoline blending of butane.

On March 28, 1994, Conoco was issued **Permit #2619-06** to construct and operate equipment to support a new Polymer Modified Asphalt (PMA) Unit at the refinery. The PMA project allowed Conoco to produce asphalt that meets the new federal specifications and to become a supplier of PMA for the region.

Installation of a 9.5-MMBtu/hr natural gas-fired process heater to heat an oil heat transfer fluid supplies heat to bring the asphalt base to 400$^{o}$F. This allows a polymer material to be mixed with it to produce PMA. A hot oil transfer pump was installed to circulate hot oil through the system. A heat exchanger (X-364) from the shutdown Propane De-asphalting (PDA) Unit was moved and installed to aid in the heating of the asphalt base. Two existing 5000-bbl asphalt storage tanks were converted to PMA mixing and curing tanks. This required the installation of additional agitators, a polymer pellet loading (blower) system and conversion of the tank steamcoil heating system to hot oil heated by the new process heater. New asphalt transfer lines, a new asphalt transfer pump, and a new 5000-bbl PMA storage tank (to replace the demolished T-50) were installed to keep the PMA separated from other asphalt products.

This permit alteration also addressed the items submitted in a letter dated November 23, 1993, for supplemental information and a request for permit clarification for Conoco's Permit #2619-03. This permit clarifies all these items, as appropriate, including the issues relating to the redesign of the SRU stack and the addition of heated air to the stack. Reference Section VI, Air Quality Impacts.

On July 28, 1995, Conoco was issued **Permit #2619-07** for the construction and operation of new equipment within the refinery's Alkylation (Alky) and Gas Recovery Plant/No.1 Amine Units. The project was referred to as the Alkylation Unit Depropanizer Project.

The existing Alkylation Unit was replaced with a new tower. The new depropanizer is located where the No.1 Bio-pond was located. Piping and valves were added, and existing equipment was located next to the new depropanizer. The old depropanizer was retained in place and may be used in the future in non-Hydrogen Fluoride (HF) service.

The decommissioned PDA Unit evaporator tower (W-3) was converted to a water wash tower to remove entrained amine from the Alky PB (Propane/Butene) olefins upstream of the PB merox prewash. New piping, valves, and instrumentation were added around W-3.

The change in air emissions associated with this project was an increase in fugitive VOC emissions, as well as additional emission of fluorides due to the installation of the new depropanizer piping and valves.

The changes made by this project were not subject to PSD review since the sum of the emission rate increases were below PSD significant emission rates for applicable pollutants.

The drains installed or reused tie into parts of the refinery's wastewater sewer system that are already subject to Standards of Performance for New Stationary Sources (NSPS), Subpart QQQ (Wastewater Treatment System VOC Emissions in Petroleum Refineries) and National Emission Standards for Hazardous Air Pollutants (NESHAP), Subpart FF (Benzene Waste Operations). These drains were equipped with tight fitting caps and have hard pipe connections to meet the required control specifications.

On July 24, 1996, Conoco was issued **Permit #2619-08** to change the daily $SO_2$ emissions limit of the 19 existing process heaters, as well as combining the 19 heaters, the Coker heater (H-3901), and the GOHDS heaters (H-8401 and H-8402) into one $SO_2$ point source within the Refinery. The project is referred to as the Existing Heater Optimization Project.

The 19 process heaters being discussed in this application are the process heaters (excluding H-3 and H-7) that were in operation prior to the construction of the Delayed Coker/Sulfur Reduction Project, which became fully operational in May of 1992. The 19 heaters are: H-1, H-2, H-4, H-5, H-10, H-11, H-12, H-13, H-14, H-15, H-16, H-17, H-18, H-19, H-20, H-21, H-22, H-23, and H-24. These 19 heaters are pooled together and regulated as one source referred to as the "19-Heater" source. Also included in this discussion are the Coker heater (H-3901) and the GOHDS heaters (H-8401 and H-8402).

The existing 19 heaters have a "bubbled" $SO_2$ permit emission limit of 30.0 ton per year (TPY) (164 lb/day) and a limitation of fuel gas $H_2S$ content of 160 ppmv (0.1 grains/dscf). With both these limitations intact, all of these heaters cannot simultaneously operate at their maximum design firing rates. This can cause un-optimized operation of the Refinery during unfavorable climatical conditions or during peak heater demand periods.

To allow all 19 heaters to simultaneously operate at their maximum firing rates, the allowable short term $SO_2$ emission limit for the "bubbled" 19 heaters must be increased. The (19) Refinery Fuel Gas Heaters/Furnaces lb/day $SO_2$ emission limitation was based on NSPS fuel gas (160 ppm $H_2S$), maximum heat input (MMBtu/hr) from the emission inventory database (AFS), and higher fuel heat value (1015 Btu/scf) from the 1990 Base-Year Carbon Monoxide Emission Inventory. By using these parameters, the daily "bubble" $SO_2$ permit limit can be raised to 386 lb/day, as was indicated in the Preliminary Determination. Conoco requested the daily limit be increased to 612 lb/day, which is equivalent to the rate used in the Billings $SO_2$ State Implementation Plan (SIP) modeling (111.7 TPY). The annual "bubble" $SO_2$ limit of 30.0 TPY was maintained.

The Department received comments from Conoco, in which Conoco contends that the maximum heat input (MMBtu/hr) from the AFS does not accurately reflect the real maximum firing rates of the heaters. After further review of the files, the Department established the total maximum firing rate for the (19) Refinery Fuel Gas Heaters/Furnaces to be 785.5 MMBtu/hr. This total maximum firing rate was identified by Conoco during the permit review of the Coker permit (Permit #2619). The maximum heat input of 785.5 MMBtu/hr and the fuel heat of 958 Btu/scf are used to calculate a new daily "bubble" $SO_2$ permit limit of 529.17 lb/day.

The change in air emissions of other criteria pollutants (carbon monoxide (CO), nitrogen oxide ($NO_X$), particulate matter (PM), and VOC) associated with this project are zero, since the Potentials to Emit (PTE) were not changed. With the current 164-lb/day $SO_2$ limit, simultaneous maximum firing of these heaters can be accomplished if the fuel gas $H_2S$ content stays below 49.75 ppmv. Conoco's amine systems produce fuel gas averaging (on an annual basis) of about 25 ppmv $H_2S$ content or less (see 1993 and 1994 Refinery EIS's). Since the emissions of CO, $NO_x$, and VOC produced are not a function of $H_2S$ content, and Conoco's current amine system can generate appropriate fuel gas to stay at or below the 164 lb/day $SO_2$ limit, the maximum potentials of these pollutants are obtainable and were not affected by this project. The PM limits for these heaters are 80 times higher than the amount generated by fuel gas combustion devices (see ARM 17.8.340); therefore, the PM emissions potential was not affected as well.

Even though Conoco's past annual average fuel gas $H_2S$ content was below 37.8 ppmv, there was still potential to run into operational limitations in peak fuel gas demand periods. The amine systems may not be able to keep the fuel gas $H_2S$ under 49.75 ppmv, rendering the refinery to operate at un-optimized rates. This was the reason for the request to raise the daily $SO_2$ emissions limit for the "19-Heater" source.

Since the proposed change to the heaters' $SO_2$ emissions limit does not reflect an annual increase in PTE, the project is not subject to PSD permitting review (threshold for $SO_2$ is 40 TPY).

In light of the $SO_2$ problem in the Billings-Laurel air shed, any change resulting in an increase of $SO_2$ emissions must have its impact determined to see if any National Ambient Air Quality Standards (NAAQS) will be violated as a result of the project. $SO_2$ modeling was completed by the Department to develop a revised $SO_2$ SIP for the Billings-Laurel area (see the Billings/Laurel $SO_2$ SIP Compliance Demonstration Report dated November 15, 1994). The "19-Heater source" was modeled using an $SO_2$ emission rate equivalent to 111.7 TPY to determine its $SO_2$ impact on the Billings-Laurel air shed. The results of this modeling showed there were no exceedances of the $SO_2$ NAAQS or the Montana standards resulting from its operation. Therefore, an increase in the permit limit from 164 lb/day to 612 lb/day of $SO_2$ did not result in any violations of $SO_2$ NAAQS or Montana standards; however, the daily emission limit set based on the NSPS limit of 0.1 grains/dscf (160 ppmv $H_2S$) is more restrictive than the SIP limit. The daily emission limit, based on NSPS, is 529.17 lb/day for the existing 19 heaters/furnaces.

With the change of a daily $SO_2$ permit limit for the "19-Heater" source, Conoco also requested that the "19-Heater" source, the Coker heater (H-3901), and the GOHDS heaters (H-8401 and H-8401) be combined into one permitted source called the "Fuel-Gas-Heaters" source. Using the existing daily $SO_2$ permit limits for the Coker heater and GOHDS heaters, an overall $SO_2$ emissions limit "bubble" of 614 lb/day would apply to the "22-Fuel-Gas-Heaters" source. The annual limit for the "22-Fuel-Gas-Heaters" source has not changed and is 45.50 TPY (30.00 + 9.60 + 2.90 + 3.00).

On April 19, 1997, Conoco was issued **Permit #2619-09** to "bubble" or combine the allowable hourly and annual $NO_X$ emission limits for the Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, and Hydrogen Plant Heaters. The $NO_X$ emission limits for these heaters were established on a pounds-per-million-Btu basis, and will be maintained.

By "bubbling" or combining the allowable hourly and annual $NO_X$ emission limits for the Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, and Hydrogen Plant Heaters allows Conoco more operational flexibility with regard to heater firing rates and heater optimization. The Coker heater still has an hourly $NO_X$ emission limit to prevent any significant impacts. This permit alteration does not allow an increase in the annual $NO_X$ emissions. Permit #2619-09 replaced Permit #2619-08.

On July 30, 1997, **Permit #2619-10** was issued to Conoco in order to comply with 40 CFR 63, Subpart R, National Emission Standards for Gasoline Distribution Facilities. Conoco installed a gasoline vapor collection system and enclosed flare for the reduction of Hazardous Air Pollutants (HAPs) resulting from the loading of gasoline. The vapor combustion unit (VCU) was added to the bulk gasoline and distillate loading rack. The gasoline vapors were collected from the trucks during loading, then routed to an enclosed flare, where combustion occurs. The project results in overall reductions in the amount of actual emissions of VOCs (94.8 TPY), with a slight increase in CO (2.1 TPY) and $NO_X$ (0.8 TPY) emissions. The actual reduction in potential emissions of VOCs is 899.5 TPY, while CO increases to 19.7 TPY and $NO_X$ increases to 7.9 TPY emissions.

In addition, Conoco requested an administrative change be made to Section II.F.5, which brought the permit requirements in alignment with the monitoring requirements specified by 40 CFR 60, Subpart QQQ, and 40 CFR 61, Subpart FF.

Because Conoco's Bulk gasoline and distillate loading tank VCU is defined as an incinerator under MCA 75-2-215, a determination that the emissions from the VCU constitutes a negligible risk to public health is required prior to the issuance of a permit to the facility. Conoco and the Department identified the following HAPs from the flare, which were used in the health risk assessment. These constituents are typical components of gasoline.

1. Benzene
2. Ethyl Benzene
3. Hexane
4. Methyl Tert Butyl Ether
5. Toluene
6. Xylenes

The reference concentrations for Ethyl Benzene, Hexane, and Methyl Tert Butyl Ether were obtained from EPA's IRIS database. The risk information for the remaining HAPs is contained in the January 1992 CAPCOA Risk Assessment Guidelines. The model performed by Conoco for the HAPs identified above, demonstrate compliance with the negligible risk requirement. Permit #2619-10 replaced Permit #2619-09.

On December 10, 1997, Conoco requested a modification to allow the continuous incineration of a PB Merox Unit off-gas stream in the firebox of Heater #16. Permit #2161-10 required the production of $SO_2$ from the sulfur containing compounds in the PB Merox Unit off-gas stream to be calculated and counted against the current $SO_2$ limitations applicable to the (22) Refinery Fuel Gas Heaters/Furnaces group. During a review of process piping and instrumentation diagrams, Conoco identified a PB Merox Unit off-gas stream incinerated in the firebox of Heater #16. A subsequent analysis of this off-gas stream revealed the presence of sulfur-containing compounds in low concentrations. The bulk of this low-pressure off-gas stream is nitrogen with some oxygen, hydrocarbons, and sulfur-containing compounds (disulfides, mercaptans). $SO_2$ produced from the continuous incineration of this stream has been calculated at approximately 1 ton per year. This off-gas stream is piped from the top of the disulfide separator through a small knock-out drum and directly into the firebox of Heater #16.

Conoco proposed to sample the PB Merox Unit disulfide separator gas stream on a monthly basis to determine the total sulfur (ppmw) present. This analysis, combined with the off-gas stream flow rate, is used to calculate the production of $SO_2$. After a year of sampling time and with the approval of the Department, Conoco may propose to reduce the sampling frequency of the PB Merox disulfide separator off-gas stream to once per quarter if the variability in the sulfur content is small (250 ppmw).

In addition, to be consistent with the wording as specified by 40 CFR 63, Subpart R, the Department replaced all references to "tank trucks" with "cargo tank" and all references to "truck loading rack" with "loading rack". Also, the first sentence in Section II.F.5 was deleted from the permit. Conoco had requested an administrative change be made to Section II.F.5, during the permitting action of #2619-10, which would bring the permit requirements in alignment with the monitoring requirements specified by 40 CFR 60, Subpart QQQ, and 40 CFR 61, Subpart FF. The Department approved the request and the correction was made, but the first sentence was inadvertently left in the permit. **Permit #2619-11** replaced Permit #2619-10.

On June 6, 2000, the Department issued **Permit #2619-12** for replacement of the B-101 thermal reactor at the Jupiter Sulphur facility. The existing B-101 thermal reactor had come to the end of its useful life and had to be replaced. The replacement B-101 thermal reactor was physically located approximately 50 feet to the north of the existing thermal reactor, due to the excessive complications that would be encountered to dismantle the old equipment and construct the new equipment in the same space. Once the piping was rerouted to the new equipment the old equipment was incapable of use and will be demolished. Given this construction scenario, the Department determined that a permit condition limiting the operation to only one thermal reactor at a time was necessary.

There was no increase in emissions due to this action. Permit #2619-12 replaced Permit #2619-11.

Conoco submitted comments on the Preliminary Determination (PD) of Permit #2619-12. The following is the result of these comments:

> In previously issued permits, Section II.A.4 listed storage tanks #4510 and #4511 as having external floating roofs with primary seal, which were liquid mounted stainless steel shoes and secondary seal equipped with a Teflon curtain or equivalent. Conoco stated that these two tanks were actually equipped with internal floating roofs with double-rim seals or a liquid-mounted seal system for VOC loss control.
>
> Section II.A.7.g.ii always listed the CPI separators as primary separators, when in fact they are secondary.

The Department accepted the comments and made the changes, accordingly, in the Department decision version of the permit.

On March 1, 2001, the Department issued **Permit #2619-13** for the installation and operation of 19 diesel-powered, temporary generators. These generators are necessary because of the high cost of electricity and supplement 18 MW of the refinery's electrical load, and 1 MW of Jupiter's electrical load. The generators are located south of the coke loading facility along with two new aboveground 20,000-gallon diesel storage tanks. The operation of the generators will not occur beyond 2 years and is not expected to last for an extended period of time, but rather only for the length of time necessary for Conoco to acquire a permanent, more economical supply of power.

Because these generators are only to be used when commercial power is too expensive to obtain, the amount of emissions expected during the actual operation of these generators is minor. In addition, the installation of these generators qualified as a "temporary source" under the PSD permitting program because the permit limited the operation of these generators to a time period of less than 2 years. Therefore, Conoco was not required to comply with ARM 17.8.804, 17.8 820, 17.8.822, and 17.8.824. Even though the portable generators were considered temporary, the Department required compliance with Best Available Control Technology (BACT) and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 was ensured. In addition, Conoco is responsible for complying with all applicable ambient air quality standards. Permit #2619-13 replaced Permit #2619-12.

On April 13, 2001, the Department issued **Permit #2619-14** for the 1982 Saturate Gas Plant Project, submitted by Conoco as a retroactive permit application. During an independent compliance awareness review that was performed in 2000, Conoco discovered that the Saturate Gas Plant should have gone through the permitting process prior to it being constructed. At the time of construction, the project likely would have required a PSD permit. However, the current potential to emit for the project facility is well below the PSD VOC significance threshold. In addition, the Saturate Gas Plant currently participates in a federally-required leak detection and repair (LDAR) program, which would meet any BACT requirements, if PSD applied. The Department agreed that a permitting action in the form of a preconstruction permit application for the Saturate Gas Plant Project was necessary and sufficient to address the discrepancy. Permit #2619-14 replaced Permit #2619-13.

On June 29, 2002, the Department issued **Permit #2619-15** to clarify language regarding the Appendix F Quality Assurance requirements for the fuel gas $H_2S$ measurement system and to include certain limits and standards associated with the Consent Decree lodged on December 20, 2001, respectively. In addition, the Department modified the permit to eliminate references to the now repealed odor rule (ARM 17.8.315), to correct the reference on conditions improperly referencing the incinerator rule (ARM 17.8.316), and to eliminate the limits on the main boiler that were less stringent than the current limit established by the Consent Decree. Permit #2619-15 replaced Permit #2619-14.

The Department received a request from Conoco on August 27, 2002, for the alteration of air quality Permit #2619-15 to incorporate the Low Sulfur Gasoline (LSG) Project into the refinery's equipment and operations. The LSG Project was being proposed to assist in complying with EPA's Tier 2 regulations. The project included the installation of a new storage vessel and minor modifications to the No.2 hydrodesulfurization (HDS) unit, GOHDS unit, and hydrogen ($H_2$) unit in order to accommodate hydrotreating additional gasoline and gas oil streams that were currently not hydrotreated prior to being blended or processed in the FCC unit. The new storage vessel was designed to store offspec gasoline during occasions when the GOHDS unit was offline.

In addition, on August 28, 2002, Conoco requested to eliminate the footnote contained in Section II.B.1.b of Permit #2619-15 stating, "Emissions [of the SRU Flare] occur only during times that the ATS unit is not operating." Further, Conoco requested to change the $SO_2$ emission limitations of 25 pounds per hour (lb/hr) for each of the SRU Flare and SRU/ATS Main Stack to a 25-lb/hr limit on the combination of the SRU Flare and SRU/ATS Main Stack. Following discussion between Conoco and the Department regarding comments received within the Department and from EPA, Conoco requested an extension to delay issuance of the Department Decision to December 9, 2002. Following additional discussion, Conoco and the Department agreed to leave the footnote in the permit for the issuance of **Permit #2619-16** and to revisit the issue at another time. Permit #2619-16 replaced Permit #2619-15.

A letter from ConocoPhillips dated December 9, 2002, and received by the Department on December 10, 2002, notified the Department that Conoco had changed its name to ConocoPhillips. In a letter dated February 3, 2003, ConocoPhillips also requested the removal of the conditions regarding the temporary power generators because the permit terms for the temporary generators were "not to exceed 2 years" and the generators have been removed from the facility. The permit action changed the name on this permit from Conoco to ConocoPhillips and removed permit terms regarding temporary generators. **Permit #2619-17** was also updated to reflect current permit language and rule references used by the Department. Permit #2619-17 replaced Permit #2619-16.

On December 11, 2003, the Department received a Montana Air Quality Permit Application from ConocoPhillips to modify Permit #2619-17 to replace the existing 143.8-million British thermal units per hour (MMBtu/hr) boilers, B-5 and B-6, with new 183-MMBtu/hr boilers equipped with low $NO_X$ burners (LNB) and flue gas recirculation (FGR) commonly referred to as ultra-low $NO_X$ burners (ULNB), B-7 and B-8, to meet the $NO_X$ emission reduction requirements stipulated in the EPA Consent Decree. On December 23, 2003, the Department deemed the application complete. This permitting action contained $NO_X$ emissions that exceed PSD significance levels. The replacement of the boilers resulted in an actual $NO_X$ reduction of approximately 89 tons per year. However, the EPA Consent Decree stipulated that reductions were not creditable for PSD purposes. Permit #2619 was also updated to reflect current permit language and rule references used by the Department. **Permit #2619-18** replaced Permit #2619-17.

C. Current Permit Action

On February 3, 2004, the Department received a Montana Air Quality Permit Application from ConocoPhillips to modify Permit #2619-18 to add a new HDS Unit (No.5), a new sour water stripper (No.3 SWS), and a new $H_2$ Unit. On March 1, 2004, the Department deemed the application complete upon submittal of additional information. The addition of these new units adds three new heaters, 41, 42, and 43, each equipped with low LNB FGR commonly referred to as ULNB. Additionally, ConocoPhillips proposes to retrofit existing external floating roof tank T-110 with a cover to allow nitrogen blanketing of the tank, to install a new storage vessel (No.5 HDS Feed storage tank) under emission point 24 above, to store feed and off-specification material for the No.5 HDS Unit, and to provide the No.1 $H_2$ Unit with the flexibility to burn refinery fuel gas (RFG). The new equipment is being added to meet the new EPA-required highway ULSD fuel sulfur standard of 100% of highway diesel that meets the 15 parts per million (ppm) highway diesel fuel maximum sulfur specification by June 1, 2006. By meeting the June 1, 2006, deadline, ConocoPhillips may claim a two-year extension for the phase in of the requirements of the Tier Two Gasoline/Sulfur Rulemaking. This permitting action results in $NO_X$ and VOC emissions that exceed PSD significance levels. Other changes are also contained in this permit. Previously in permit condition II.A.1 it was stated that the emergency flare tip must be based at 148-feet elevation. After a physical survey of the emergency flare it was determined that the actual height of the flare tip is 141.5-feet elevation. The current permit changes permit condition II.A.1 from 148-feet of elevation to 142-feet plus or minus 2 feet of elevation and changes the reference from ARM 17.8.752 to ARM 17.8.749. Permit #2619-19 has also been updated to reflect current permit language and rule references used by the Department. **Permit #2619-19** replaces Permit #2619-18.

D. Additional Information

Additional information, such as applicable rules and regulations, BACT/Reasonably Available Control Technology (RACT) determinations, air quality impacts and environmental assessments, is included in the analysis associated with each change to the permit.

II. Applicable Rules and Regulations

The following are partial explanations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the ARM and are available, upon request, from the Department. Upon request, the Department will provide references for locations of complete copies of all applicable rules and regulations or copies where appropriate.

A. ARM 17.8, Subchapter 1 - General Provisions, including, but not limited to:

1. <u>ARM 17.8.101 Definitions</u>. This rule includes a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. <u>ARM 17.8.105 Testing Requirements</u>. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment,

including instruments and sensing devices, and shall conduct tests, emission or ambient, for such periods of time as may be necessary using methods approved by the Department. ConocoPhillips shall also comply with monitoring and testing requirements of this permit.

3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the Department, any source, or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Montana Clean Air Act, 75-2-101, *et seq*., Montana Code Annotated (MCA).

   ConocoPhillips shall comply with all requirements contained in the Montana Source Test Protocol and Procedures Manual, including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from the Department upon request.

4. ARM 17.8.110 Malfunctions. (2) The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation or to continue for a period greater than 4 hours.

5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means which, without resulting in reduction in the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner that a public nuisance is created.

B. ARM 17.8, Subchapter 2 - Ambient Air Quality, including, but not limited to:

1. ARM 17.8.204 Ambient Air Monitoring
2. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
3. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
4. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
5. ARM 17.8.213 Ambient Air Quality Standard for Ozone
6. ARM 17.8.214 Ambient Air Quality Standard for Hydrogen Sulfide
7. ARM 17.8.221 Ambient Air Quality Standard for Visibility
8. ARM 17.8.223 Ambient Air Quality Standard for $PM_{10}$

ConocoPhillips must comply with the applicable ambient air quality standards. See Section VI Ambient Air Impact Analysis.

C. ARM 17.8, Subchapter 3 - Emission Standards, including, but not limited to:

1. ARM 17.8.304 Visible Air Contaminants. This rule requires that no person may cause or authorize emissions to be discharged to an outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

2. ARM 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of less than 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate matter. (2) Under this rule, ConocoPhillips shall not cause or authorize the use of any street, road, or

parking lot without taking reasonable precautions to control emissions of airborne particulate matter.

3. ARM 17.8.309 Particulate Matter, Fuel Burning Equipment. This rule requires that no person shall cause, allow or permit to be discharged into the atmosphere particulate matter caused by the combustion of fuel in excess of the amount determined by this rule.

4. ARM 17.8.316 Incinerators. This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any incinerator, particulate matter in excess of 0.10 grains per standard cubic foot of dry flue gas, adjusted to 12% carbon dioxide and calculated as if no auxiliary fuel had been used. Also, no person shall cause or authorize to be discharged into the outdoor atmosphere from any incinerator emissions that exhibit an opacity of 10% or greater averaged over 6 consecutive minutes.

5. ARM 17.8.322 Sulfur Oxide Emissions--Sulfur in Fuel. (4) Commencing July 1, 1972, no person shall burn liquid or solid fuels containing sulfur in excess of 1 pound of sulfur per million Btu fired. (5) Commencing July 1, 1971, no person shall burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 cubic feet of gaseous fuel, calculated as hydrogen sulfide at standard conditions. ConocoPhillips will burn RFG pressure swing adsorption (PSA) gas, or natural gas, which will meet this limitation.

6. ARM 17.8.340 Standard of Performance for New Stationary Sources. This rule incorporates, by reference, 40 CFR 60, NSPS. ConocoPhillips is considered an NSPS affected facility under 40 CFR 60 and is subject to NSPS Subparts including, but not limited to:

   a. Subpart A, General Provisions, applies to all equipment or facilities subject to an NSPS Subpart as listed below.

   b. Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units shall apply to all affected boilers at the facility which were constructed after June 19, 1984, are larger than 100 MMBtu/hr, and combust fossil fuel.

   c. Subpart J, Standards of Performance for Petroleum Refineries, shall apply to all of the heaters and boilers at the ConocoPhillips refinery, the Claus units at the Jupiter sulfur recovery facility, and any other applicable equipment.

   d. Subpart Ka, Standards of Performance for Volatile Organic Liquid Storage Vessels, shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after May 18, 1978, and prior to July 23, 1984. These requirements shall be as specified in 40 CFR 60.110a through 60.115a. The affected tanks include, but are not limited to:

| Tank Number | Contents |
|---|---|
| #100-Ka* | Asphalt |
| #101-Ka* | Asphalt |
| #102-Ka | Gasoline |
| #104-Ka* | Vacuum Resid |

* Currently exempt from all emission control provisions due to vapor pressure of materials stored.

e. Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels, shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984. These requirements shall be as specified in 40 CFR Part 60.110b through 60.117b. The affected tanks include, but are not limited to, the following:

| Tank Number | Contents |
|---|---|
| #36-Kb | Slop oil |
| #72-Kb | Gasoline |
| #107-Kb* | Residue |
| #110-Kb | Diesel, No.5 HDS Unit feed, and cracked distillate |
| #162-Kb* | Groundwater HC recovery |
| #T-3201* | Polymer Modified Asphalt (PMA) |
| #T-4524 | LSG Tank (Off-spec gasoline tank) |
| No.5 HDS Feed storage tank | No.5 HDS Unit feed |

* Currently exempt from all emission control provisions due to vapor pressure of materials stored.

f. Subpart UU, Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture, shall apply to, but not be limited to, asphalt storage tank T-3201, and any other applicable storage tanks that commenced construction or modification after May 26, 1981. Asphalt storage tank T-3201 shall comply with the standards in 40 CFR 60.472(c), and 0% opacity, except for one consecutive 15-minute period in any 24-hour period when transfer lines are being blown for clearing. The PMA unit will be operating at 400$^{o}$F, well under the asphalt's smoking temperature of 450$^{o}$F; therefore, the tank vent opacity will always have 0% opacity. There are no record-keeping requirements under this subpart. However, any malfunction must be reported as required under ARM 17.8.110, Malfunctions.

g. Subpart GGG, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries, shall apply to, but not be limited to, the delayed coker unit, cryogenic unit, hydrogen membrane unit, gasoline merox unit, crude vacuum unit, gas oil hydrotreater unit (consisting of a reaction section, fractionation section, and an amine treating section), 20.0-MMscfd hydrogen plant feed system, Alkylation Unit Butane Defluorinator Project (consisting of heat exchangers X-453, X-223, X-450, X-451, X-452; pump P-646; and vessels D-130, D-359, D-360), PMA process unit, Alkylation Unit Depropanizer Project, new fugitive components associated with boilers B-7 and B-8; the fugitive components associated with the new No.2 $H_2$ Unit and the new No.5 HDS Unit; and any other applicable equipment constructed or modified after January 4, 1983.

h. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems shall apply to, but not be limited to, the coker unit drain system, desalter wastewater break tanks, CPI separators, gas oil hydrotreater, 20.0-MMscfd hydrogen plant, C-23 compressor station, Alkylation Unit Butane Defluorinator Project, Alkylation Unit Depropanizer Project, the new individual drain system in the No.2 $H_2$ Unit and the new No.5 HDS Unit, and any other applicable equipment.

i. All other applicable subparts and referenced test methods.

7. ARM 17.8.341 Standards of Performance for Hazardous Air Pollutants. ConocoPhillips shall comply with the standards and provisions of 40 CFR Part 61, as listed below:

a. Subpart A. General Provisions applies to all equipment or facilities subject to a NESHAP Subpart as listed below.

b. Subpart FF, National Emission Standards for Benzene Waste Operations shall apply to, but not be limited to, all new or recommissioned wastewater sewer drains associated with the Alkylation Unit Depropanizer Project, the refinery's existing sewer system (including maintenance and water draw down activities of the LSG tank involving liquids that may include small concentrations of benzene), the new individual drain system for the waste streams associated with the No.2 $H_2$ Unit and the No.5 HDS Unit, and Tanks 34 and 35.

c. Subpart M, National Emission Standard for Asbestos shall apply to, but not be limited to, the demolition and/or renovation of regulated asbestos containing material.

8. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. The source, as defined and applied in 40 CFR Part 63, shall comply with the requirements of 40 CFR Part 63, as listed below:

a. Subpart A, General Provisions, applies to all NESHAP source categories subject to a Subpart as listed below.

b. Subpart R, National Emission Standards for Gasoline Distribution Facilities, shall apply to, but not limited to, the Bulk Loading Rack.

c. Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.

d. Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters, when effective, shall apply to, industrial, commercial, or industrial boiler or process heaters that are located at, or are part of a major source of HAP emissions.

D. ARM 17.8, Subchapter 4 - Stack Height and Dispersion Techniques, including, but not limited to:

1. ARM 17.8.401 Definitions. This rule includes a list of definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.402 Requirements. ConocoPhillips must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP). The proposed height of the new or altered stack for ConocoPhillips is below the allowable 65-meter GEP stack height.

E. ARM 17.8, Subchapter 5 - Air Quality Permit Application, Operation and Open Burning Fees, including, but not limited to:

1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to the Department. ConocoPhillips submitted the appropriate permit application fee for the current permit action.

2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminants holding an air quality permit, excluding an open burning permit, issued by the Department. The air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

   The annual assessment and collection of the air quality operation fee, described above, shall take place on a calendar-year basis. The Department may insert into any final permit issued after the effective date of these rules, such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions that prorate the required fee amount.

F. ARM 17.8, Subchapter 7 - Permit, Construction and Operation of Air Contaminant Sources, including, but not limited to:

1. ARM 17.8.740 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit alteration to construct, alter or use any air contaminant sources that have the PTE greater than 25 tons per year of any pollutant. ConocoPhillips has the PTE greater than 25 tons per year of PM, particulate matter with an aerodynamic diameter of 10 microns or less ($PM_{10}$), $NO_X$, CO, VOC, and $SO_2$; therefore, an air quality permit is required.

3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.

4. ARM 17.8.745 Montana Air Quality Permits—Exclusion for De Minimis Changes. This rule identifies the de minimis changes at permitted facilities that do not require a permit under the Montana Air Quality Permit Program.

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. This rule requires that a permit application be submitted prior to installation, alteration or use of a source. ConocoPhillips submitted the required

permit application for the current permit action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. ConocoPhillips submitted an affidavit of publication of public notice for the February 6, 2004, issue of the *Billings Gazette*, a newspaper of general circulation in the Town of Billings in Yellowstone County, as proof of compliance with the public notice requirements.

6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.

7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The required BACT analysis is included in Section III of this permit analysis.

8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the Department at the location of the source.

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving ConocoPhillips of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*.

10. ARM 17.8.759 Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those permit applications that do not require the preparation of an environmental impact statement.

11. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or altered source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued.

12. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).

13. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. A source may not increase its emissions beyond those found

in its permit unless the source applies for and receives another permit.

14. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of Intent to Transfer, including the names of the transferor and the transferee, is sent to the Department.

15. ARM 17.8.770 Additional Requirements for Incinerators. This rule specifies the additional information that must be submitted to the Department for incineration facilities subject to 75-2-215, MCA.

G. ARM 17.8 - Subchapter 8, Prevention of Significant Deterioration of Air Quality, including, but not limited to:

1. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in this subchapter.

2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications -- Source Applicability and Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification with respect to each pollutant subject to regulation under the FCAA that it would emit, except as this subchapter would otherwise allow.

   ConocoPhillips' existing petroleum refinery in Billings is defined as a "major stationary source" because it is a listed source with the PTE more than 100 tons per year of several pollutants ($SO_2$, CO, and VOCs). ConocoPhillips' proposed modification is defined as a "major modification."

H. ARM 17.8, Subchapter 12 - Operating Permit Program Applicability, including, but not limited to:

1. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any stationary source having:

   a. PTE > 100 tons/year of any pollutant;

   b. PTE > 10 tons/year of any one HAP, PTE > 25 tons/year of a combination of all HAPs, or a lesser quantity as the Department may establish by rule; or

   c. Sources with the PTE > 70 tons/year of $PM_{10}$ in a serious $PM_{10}$ nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program Applicability. (1) Title V of the FCAA Amendments of 1990 requires that all sources, as defined in ARM 17.8.1204 (1), obtain a Title V Operating Permit. In reviewing and issuing Air Quality Permit #2619-19 for ConocoPhillips, the following conclusions were made:

   a. The facility's PTE is greater than 100 tons/year for several pollutants.

   b. The facility's PTE is greater than 10 tons/year for any one HAP and greater than 25 tons/year of all HAPs.

c. This source is not located in a serious $PM_{10}$ nonattainment area.

d. This facility is subject to NSPS requirements.
e. This facility is subject to current NESHAP standards.

f. This source is not a Title IV affected source, nor a solid waste combustion unit.

g. This source is not an EPA designated Title V source.

Based on these facts, the Department determined that ConocoPhillips is a major source of emissions as defined under Title V. ConocoPhillips submitted a Title V Operating Permit application on June 12, 1996, and the Title V Permit #OP2619-01 was issued Final on December 2, 2003.

III. BACT Determination

A BACT determination is required for each new or altered source. ConocoPhillips shall install on the new or altered source the maximum air pollution control capability, which is technically practicable and economically feasible, except that BACT shall be utilized.

ConocoPhillips submitted a BACT analysis in Permit Application #2619-19, in a top-down fashion, addressing some available methods of controlling $NO_X$, CO, VOC, PM, and $SO_2$ emissions from the new equipment installed as a result of the ULSD project. The Department reviewed these methods, as well as previous BACT determinations. The Department has reviewed the following control options in order to make the following BACT determination.

The control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

A. Identify All Control Technologies

ConocoPhillips identified all available control options for the emissions unit in question. Control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and regulated pollutant being evaluated. The following categories of technologies are addressed in identifying candidate control alternatives:

Demonstrated add-on control technologies applied to the same emissions unit at other similar source types;

Add-on controls not demonstrated for the source category in question but transferred from other source categories with similar emission stream characteristics;

Process controls such as combustion or alternative production processes;

Add-on control devices serving multiple emission units in parallel; and

Equipment or work practices, especially for fugitive or area emission sources where add-on controls are not feasible.

1. $NO_X$

$NO_X$ will be formed during the combustion reaction of natural gas, RFG, and PSA vent gas in the process heaters that will be installed as part of the ULSD project. There are three mechanisms for $NO_X$ formation: thermal $NO_X$, prompt $NO_X$, and fuel-bound $NO_X$. Thermal $NO_X$ formation occurs by the high temperature dissociation and subsequent reaction of combustion air molecular nitrogen ($N_2$) and oxygen ($O_2$), via the Zeldovich mechanism. Much of the $NO_X$ resulting from the thermal $NO_X$ mechanism is generated in the high temperature zone near the burner and is affected by $O_2$ concentration, peak temperature, and the time of exposure at peak temperature. Thermal $NO_X$ generation increases exponentially with temperature, and above 2000 degrees Fahrenheit, it is generally the predominant mechanism in combustion processes that involve fuel streams that do not contain significant amounts of chemically bound nitrogen, such as natural gas and RFG. Prompt $NO_X$ occurs at the flame front through the relatively fast reaction between $N_2$ and $O_2$ molecules in the combustion air and fuel hydrocarbon radicals that are intermediate species formed during the combustion process. Prompt $NO_X$ is usually responsible for no more than 20 ppmv $NO_X$ in RFG fueled combustion equipment. However, because it is an important mechanism in lower temperature combustion processes, it can represent a significant portion of $NO_X$ emissions when emissions are reduced to extremely low levels associated with typical $NO_X$ combustion control techniques. Fuel-bound $NO_X$ is formed by the direct oxidation of organo-nitrogen compounds contained in the fuel stream. Gaseous fuels such as natural gas and RFG typically contain negligible fuel bound nitrogen concentrations.

The table below describes the potential BACT control options used to control $NO_X$ emissions from refinery process heaters identified during a search of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database, a review of EPA's January 19, 2001, memorandum titled "BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic Compounds at Tier 2/Gasoline Refinery Projects" (Tier 2 BACT/LEAR Memorandum), and an assessment of recently issued Department determinations. Rank 1 identifies the control option with the highest $NO_X$ emissions reduction potential.

| **Heater BACT $NO_X$ Control** | | |
|---|---|---|
| **Rank** | **Control Technology** | **Reduction (%)** |
| 1 | SCR with ULNB | 92-96 |
| 2 | SNCR with ULNB | 85-93 |
| 3 | SCR | 80-90 |
| 4 | ULNB | 68-84 |
| 5 | SNCR | 19-60 |
| 6 | No Additional Control | 0 |

a. Selective Catalytic Reduction (SCR) with ULNB

The top ranked control alternative considered is SCR in combination with ULNB. Based on review of the RBLC database, no entries were located that documented the use of SCR in combination with ULNB on refinery process heaters. However, EPA's Tier 2 BACT/LAER Memorandum documents that this combined control option has been demonstrated on a limited number of refinery process heaters located in California that burn a combination of refinery fuel gas and natural gas. A search of the South Coast Air Quality Management District BACT Clearinghouse database identified two facilities in California with refinery process heaters equipped with SCR in combination with ULNB. However, both of these facilities are located in an air quality region that is designated as non-attainment with respect to ozone.

SCR is a post-combustion flue gas treatment technique for the selective catalytic chemical reduction of nitric oxide (NO) and nitrogen dioxide ($NO_2$) to molecular nitrogen and water vapor. In the SCR process, a reducing agent, ammonia ($NH_3$), is mixed with the combustion device exhaust stream and then passed through a catalyst bed, which serves to lower the activation energies necessary for the $NO_X$ reduction reactions to occur and to increase the $NO_X$ reduction reaction rates. The $NO_X$ and $NH_3$ are adsorbed onto the catalyst surface to form an activated complex, and then catalytic reaction occurs resulting in nitrogen and water, which are desorbed from the catalyst surface and into the flue gas.

b. Selective Non-Catalytic Reduction (SNCR) with ULNB

The second most stringent alternative considered is SNCR in combination with ULNB. The SNCR process is similar to the SCR process in that a reagent reacts with $NO_X$ to form nitrogen and water vapor. The difference between the two processes is that, SNCR does not utilize a catalyst to promote the chemical reduction of $NO_X$. The most common reagents used in SNCR systems are injected into the flue gas stream within a specific temperature window to ensure optimum reduction of $NO_X$. The SNCR process requires extremely high flue gas temperatures to disassociate $NO_X$ to nitrogen and water vapor. Duct burners would be necessary to raise the flue gas temperature of the exhaust streams.

c. SCR

The third most stringent alternative considered is SCR without the combination of combustion controls.

d. ULNB

The fourth most stringent control alternative considered is ULNB technology. A LNB with FGR is commonly referred to as ULNB. $NO_X$ reduction combustion control equipment and techniques consist of a range of designs and performance levels, which are dependant on the type of fuel fired in the combustion unit and the function of the combustion source. ULNBs utilize the stage fuel concept and either inspirate flue gases from the radiant section into the primary and secondary combustion reaction zones or utilize external flue gas recirculation, both of which serve to rapidly mix the fuel and air near the burner exit while controlling flame temperature. The rapid fuel and air mixing nearly eliminates the formation of prompt $NO_X$ and also virtually eliminates incomplete combustion pollutants, while the flue gas recirculation minimizes the generation of thermal $NO_X$ by limiting the peak flame temperature due to lower overall excess oxygen concentration.

e. SNCR

One of the least stringent control alternative considered is SNCR without the combination of combustion controls.

f. No Additional Control

2. VOC

This section presents BACT analysis for the following sources that will be added or modified as part of the ULSD project: No.5 HDS Feed storage tank, Tank T-110, process unit fugitive components, wastewater drains, NO.5 HDS Charge Heater, No.5 HDS Stabilizer Reboiler Heater, No.2 $H_2$ Unit Reformer Heater, and deaerator vent.

a. Process Heaters

Good combustion practices and good engineering design

Process heater VOC emissions are generated as a result of incomplete fuel combustion. A search of the EPA's RBLC database and recent Department decisions indicated the use of good combustion practices and engineering design for heaters/furnaces as the best/control for VOC emissions.

b. Storage Tanks

i. Installation of pressure vessel with no vent to atmosphere
ii. Routing storage vessel emissions to flare or equivalent control device
iii. Installation of internal floating roofs (IFR) or external floating roofs (EFR) equipped with NSPS and NESHAP compliant fittings

Storage tank VOC emissions are generated from two processes during the storage of organic materials. These mechanisms include working and breathing loss emissions, which occur during normal storage vessel operations. Working loss emissions are generated when material is pumped into a tank displacing the saturated vapor space to the atmosphere. Breathing losses are generated from evaporative losses of organic material that is affected by ambient temperatures, surface area, and wind speeds.

c. Process Unit Fugitive Components

Implement an NSPS Subpart GGG and NESHAP Subpart CC compliant LDAR monitoring program

Process unit fugitive VOC emissions are generated when process gases and liquids leak from fugitive components such as valves, pumps, or connectors. The quantity of emissions depends greatly on the vapor pressure of the particular stream processed by the fugitive component.

d. Deaerator Vent

The use of optimal process design and proper operation of the No.2 $H_2$ Unit

Deaerators are mechanical devices that remove dissolved gasses from feed water to steam generating units or processes. The deaeration process protects the process unit from the effects of corrosive gases. It accomplishes this by reducing the concentration of dissolved oxygen and carbon dioxide to a level where corrosion is minimized. Deareators use steam to heat the water to the full saturation temperature corresponding to the stream pressure in the deaerator and to scrub out and carry away dissolved gases. Deareator emissions are generated when the non-condensable gases are removed from the steam system.

Hydrogen will be generated in the No.2 $H_2$ Unit via the steam reforming process in which hydrocarbons and steam react to form $H_2$ and carbon dioxide ($CO_2$). Undesirable side reactions will generate VOCs that will be condensed along with unreacted steam from the process. When the VOC containing condensate is recycled to the deaerator to be processed before being recycled for steam generation, the VOC will be desorbed, along with oxygen and $CO_2$, and emitted to the atmosphere through the deaerator vent.

e. Startup/Shutdown and Maintenance Wastewater Drains

Install NSPS Subpart QQQ and NESHAP Subpart FF compliant drains

As part of the installation of the new No.5 HDS Unit and the No.2 $H_2$ Unit, several new drains will be added and utilized for startup, shutdown and maintenance operations

3. CO

Process Heaters

Good combustion practices and good engineering design

Current burner design has reduced the inverse relationship between the conditions that contribute to CO formation but result in lower emission of $NO_X$, allowing venders to guarantee low CO emissions from low $NO_X$ burners. A review of EPA’s RBLC database indicated that good combustion practices and low $NO_X$ burners are the most stringent control techniques.

4. $PM/PM_{10}$

Process Heaters

Good combustion practices and good engineering design

A review of EPA’s RBLC database indicated that good combustion practices and the use of clean burning fuels are the most stringent control techniques for the control of PM emissions from gaseous fuels combustion.

5. $SO_2$

Process Heaters

Good combustion practices and good engineering design

$SO_2$ emissions from fuel burning equipment are directly related to the amount of sulfur content of the fuel. EPA's RBLC database indicates that fuel sulfur content limits are considered BACT for $SO_2$ emissions. The new heaters are subject to NSPS Subpart J, which limits the sulfur content in fuels. Also, ARM 17.8.322 limits the sulfur content in fuels.

B. Eliminate Technically Infeasible Options

The technical feasibility of the control options identified in the list above is evaluated with respect to the source-specific factors. A demonstration of technical infeasibility should be clearly documented and shown, based on physical, chemical, and/or engineering principles. If options are eliminated, the analysis should show technical difficulties would preclude the successful use of the control options on the emissions unit under review. Technically infeasible control options may then be eliminated from further consideration. The following criteria are considered in determining technical feasibility: previous commercial scale demonstrations, precedents based on previous permits, and technology transfer from similar sources.

1. $NO_X$

a. SNCR with ULNB

SNCR with ULNB was eliminated as a technically infeasible option because existing data indicate that, in practice, the $NO_X$ reduction efficiencies of SNCR systems are significantly less than SCR systems. Also, the SNCR process requires extremely high flue gas temperatures without the addition of other chemicals to increase the temperature window, to disassociate $NO_X$ to nitrogen and water vapor. As a result, duct burners would be necessary to raise the flue gas temperature of the exhaust streams, which would result in more combustion pollutant emissions and additional energy consumption. The attainment of proper mixing of the reagent with flue gas at various combustion unit loads can be difficult. There are numerous design and operational technical difficulties related to the SNCR process. SNCR may increase undesirable emissions such as CO $N_2O$ and $NH_3$.

Because the control option has not been demonstrated to achieve such theoretical $NO_X$ emission reductions, there are several design and operational technical difficulties associated with SNCR, and there may be adverse environmental impacts associated with SNCR operation, this control option was eliminated as a technically infeasible.

b. SNCR

The SNCR without the combination of combustion controls was eliminated as an option because SNCR, though not technically infeasible, is technically inferior to the other control technologies being considered.

2. VOC

Storage Tanks

Installation of pressure vessel with no vent to atmosphere
Due to the specific application of these tanks, a completely sealed vessel (pressure vessel) would not be technically feasible because of the pressure involved with the products to be stored in the tanks.

C. Rank Remaining Technologies by Control Effectiveness

This is an assessment and documentation of the emissions limit achievable with each technically feasible alternative. Available control technology options deemed technically feasible are ranked in order of pollutant removal effectiveness. The control option that results in the highest pollution removal value is considered the top control alternative.

1. $NO_X$

| Heater $NO_X$ BACT Control | | |
|---|---|---|
| **Rank** | **Control Technology** | **Reduction (%)** |
| 1 | SCR with ULNB | 92-96 |
| 2 | SCR | 80-90 |
| 3 | ULNB | 68-84 |
| 4 | No Additional Control | 0 |

2. VOC

| VOC BACT Control | | | |
|---|---|---|---|
| **Source Description** | **Rank** | **Control Technology** | **Reduction (%)** |
| Process Heaters | 1 | Good combustion practices and good engineering design | NA |
| Storage Tanks | 1 | Routing storage vessel emissions to flare or equivalent control device | 98 |
| | 2 | Installation of IFR or EFR equipped with NSPS and NESHAP compliant fittings | 85-97 |
| Process Unit Fugitive Components | 1 | NESHAP CC/NSPS GGG Requirements | NA |
| Deaerator Vent | 1 | Good combustion practices and good engineering design | NA |
| Startup/Shutdown and Maintenance Wastewater Drains | 1 | NESHAP FF/NSPS QQQ Requirements | NA |

D. Evaluate Most Effective Controls and Document Results

After the identification of available and technically feasible control technology options, the energy, environmental, and economic impacts are considered. To reject the top alternative, it must be demonstrated that this control alternative is unreasonable based on the impacts analysis results. If a control technology is determined to be technically unreasonable or unreasonable based on high cost effectiveness, or to cause adverse energy or environmental impacts, the control technology is rejected and the impacts analysis is performed on the next most stringent control alternative. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT.

1. $NO_X$

a. SCR with ULNB

Technical difficulties associated with SCR systems include the temperature of the flue gas stream that is critical in the design and operation of an SCR unit because a specific type of catalyst must be chosen to ensure optimum $NO_X$ reduction. If the temperature of the flue gas drops below the optimum operating window of the selected catalyst, then the $NO_X$ reduction of the SCR system will decrease and the quantity of ammonia reagent emitted will increase. If the temperature of the flue gas rises above the optimum operating window of the catalyst, then the ammonia reagent can be oxidized and generate additional $NO_X$. With any fuel that contains an appreciable level of sulfur compounds there are significant concerns with regards to maintaining the correct SCR operating conditions. Incorrect SCR operating conditions can generate ammonium salts formed as byproducts in undesirable side reactions and can cause plugging when they accumulate on the catalyst surface or corrosion of downstream equipment on which they may condense. The salts can be generated when the SCR operating temperature is too low because $NH_3$ that does not react with $NO_X$ is available to react with $SO_3$. Additional operating costs would be required to remove the sulfur content in the fuel gas and to provide supplemental heat to ensure an SCR temperature above the dew point of the ammonium salts.

Environmental and safety concerns associated with the operation of an SCR system include, the operation of the SCR with a molar $NH_3/NO_X$ ratio greater than that required by stoichiometry of the reduction chemical reaction in order to achieve optimal $NO_X$ reduction, referred to as ammonia slip. Ammonia slip results in the emission of odorous $NH_3$ into the atmosphere and can react with ambient air to generate fine particulate matter that scatters light and may result in regional visibility problems. The formation of ammonium salts which can cause visible plumes and elevated opacity readings from the stack. The depleted catalyst may be considered hazardous waste. Safety considerations associated with the transportation, storage, and handling of large amounts of anhydrous ammonia.

The cost effectiveness values in the tables below are based on the combined control strategy annual cost and the total $NO_X$ emission reduction potential for the combined SCR and ULNB control system.

| SCR with ULNB Cost Effectiveness | | | | |
|---|---|---|---|---|
| **Source** | **Initial Capital Expenditure ($)** | **Annual Operating Cost ($)** | **$NO_X$ Reduction (tpy)** | **Cost Effectiveness ($/ton)** |
| No.5 HDS Charge Heater | 1,441,165 | 275,656 | 11.85 | 23,266 |
| No.5 HDS | 1,578,489 | 341,770 | 39.22 | 8,714 |

| | | | | |
|---|---|---|---|---|
| Stabilizer Reboiler Heater | | | | |
| No.$H_2$ Unit Reformer Heater | 1,480,757 | 342,638 | 95.41 | 3,591 |

ULNB technology alone can achieve $NO_X$ emissions during normal operations of approximately 81-84%, when SCR is applied to the proposed new heaters along with the ULNB the combined $NO_X$ reduction potential becomes approximately 95% for each heater compared to uncontrolled $NO_X$ emission rates. Applying SCR control in addition to ULNB for the new heaters could result in a $NO_X$ reduction of an additional 11%. The additional annual cost of installing and operating an SCR would range from approximately $273,911.00 to $336,654.00 per heater. This equates to an incremental cost effectiveness ranging from $25,379.00 to $85,444.00 per ton of additional $NO_X$ removed. The table below lists the estimated incremental cost effectiveness values for SCR when applied to ULNB controlled emissions from the proposed heaters.

| Incremental Cost Effectiveness of Adding SCR to ULNB | | | | | |
|---|---|---|---|---|---|
| **Source** | **ULNB Annual Operating Cost ($)** | **SCR Annual Operating Cost ($)** | **ULNB $NO_X$ Reduction (tpy)** | **SCR $NO_X$ Reduction (tpy)** | **SCR Incremental Cost Effectiveness ($/ton)** |
| No.5 HDS Charge Heater | 1,745 | 273,911 | 8.64 | 3.21 | 85,444 |
| No.5 HDS Stabilizer Reboiler Heater | 11,719 | 330,051 | 28.61 | 10.61 | 31,101 |
| No.$H_2$ Unit Reformer Heater | 5,984 | 336,654 | 82.14 | 13.27 | 25,379 |

Because of the technical difficulties, environmental concerns, safety issues, and the annual costs associated with the operation of an SCR unit with the ULNB, this combined control technology alternative was rejected as BACT for the control of $NO_X$ emissions.

b. SCR

The second most stringent alternative considered for the control of $NO_X$ emissions is SCR without the combination of combustion controls. There are adverse technical, environmental, and safety issues, discussed in Section D for SCR with ULNB, associated with the installation and operation of SCR systems for combustion sources firing refinery fuel gas, that oppose SCR's selection as BACT. The table below documents the cost effectiveness of an SCR system.

| SCR Cost Effectiveness | | | | |
|---|---|---|---|---|
| **Source** | **Initial Capital Expenditure ($)** | **Annual Operating Cost ($)** | **$NO_X$ Reduction (tpy)** | **Cost Effectiveness ($/ton)** |
| No.5 HDS Charge Heater | 1,477,524 | 285,636 | 10.46 | 27,311 |
| No.5 HDS Stabilizer Reboiler Heater | 1,546,736 | 350,705 | 34.62 | 10,130 |

| | | | | |
|---|---|---|---|---|
| No.$H_2$ Unit Reformer Heater | 1,507,645 | 380,429 | 82.21 | 4,627 |

Because of the technical difficulties, environmental concerns, safety issues, and the relatively high annual costs associated with the operation of an SCR unit when compared to ULNB, and the fact that ULNB can achieve a nearly equivalent level of $NO_X$ emissions reduction at a much lower annual cost than SCR and without comparable technical, environmental, and safety concerns, the SCR alone control technology alternative was rejected as BACT.

c. ULNB

The third most stringent alternative considered for the control of $NO_X$ emissions is ULNB. $NO_X$ emission levels of 0.03 lb/MMBtu represent the vendor guarantee for the heaters when operated at the conditions proposed as part of this permitting action. An emission limit of 0.03 lb/MMBtu equates to a $NO_X$ reduction ranging from 8.64 to 82.14 tpy when compared to uncontrolled baseline emissions, a reduction of between 69% and 84%.

| **ULNB Cost Effectiveness** | | | | |
|---|---|---|---|---|
| **Source** | **Initial Capital Expenditure ($)** | **Annual Operating Cost ($)** | **$NO_X$ Reduction (tpy)** | **Cost Effectiveness ($/ton)** |
| No.5 HDS Charge Heater | 12,987 | 1,745 | 8.64 | 202 |
| No.5 HDS Stabilizer Reboiler Heater | 87,201 | 11,719 | 28.61 | 410 |
| No.$H_2$ Unit Reformer Heater | 44,528 | 5,984 | 82.14 | 73 |

According to the RBLC database, ULNB has been recently approved as BACT for numerous refinery process heaters and it has been identified as the most common $NO_X$ control technology currently used for combustion sources located at refineries. ULNBs do not present any of the dangers to workers or to the surrounding community that accompany SCR and SNCR. ULNBs could in some cases cause a loss in combustion efficiency, but for a new heater and burner system, their use can be optimized in the unit design and thus result in little or no impact on thermal efficiency.

Installation and operation of ULNBs is more cost effective than SCR, and the achievable $NO_X$ reduction of the two control options is nearly identical.

2. VOC

Storage Tanks

a. Routing storage vessel emissions to flare or equivalent control device

The use of a carbon canister system or a combustion device would result in a waste component stream or combustion pollutants not associated with IFR or EFR tanks seals.

b. NSPS Subpart Kb and NESHAP Subpart CC IFR compliant seals and fittings and to maintain tank T-110 NSPS Subpart Kb and NESHAP Subpart CC compliant floating roof seals and fittings

E. Select BACT

1. Process Heaters

a. $NO_X$

The most effective control option not eliminated above is proposed as BACT for the pollutant and emission unit under review.

Because ULNBs have fewer technical difficulties, environmental concerns, safety issues, and do not have the high annual costs associated with the operation of an SCR unit, and the fact that ULNBs can achieve a nearly equivalent level of $NO_X$ emissions reduction, the ULNB control technology alternative and an emission limit of 0.03 lb/MMBtu was accepted as BACT.

b. CO

Current burner design has reduced the inverse relationship between the conditions that contribute to CO formation but result in lower emission of $NO_X$, allowing venders to guarantee low CO emissions from low $NO_X$ burners. A review of EPA's RBLC database indicated that good combustion practices and low $NO_X$ burners are the most stringent control techniques. ConocoPhillips' proposal to combust clean burning fuels and utilize good combustion practices and engineering design to comply with CO control requirements constitutes BACT.

c. $PM/PM_{10}$

A review of EPA's RBLC database indicated that good combustion practices and the use of clean burning fuels are the most stringent control techniques for the control of PM emissions from gaseous fuels combustion. ConocoPhillips' proposal to combust clean burning fuels, utilize good combustion practices and engineering design, and comply with ARM 17.8.309 in order to comply with the PM control requirements constitutes BACT.

d. $SO_2$

$SO_2$ emissions from fuel burning equipment are directly related to the amount of sulfur content of the fuel. EPA's RBLC database indicates that fuel sulfur content limits are considered BACT for $SO_2$ emissions. The new heaters are subject to NSPS Subpart J, which limits the sulfur content in fuels. Also ARM 17.8.322 limits the sulfur content in fuels. ConocoPhillips' proposal to comply with $SO_2$ emission control requirements by meeting the RFG sulfur content limits established in NSPS Subpart J and ARM 17.8.322 constitutes BACT.

e. VOC

Process Heater VOC emissions are generated as a result of incomplete fuel combustion. A search of EPA's RBLC database indicated the use of "good combustion practices and engineering design" for heaters/furnaces as the best control for VOC emissions. ConocoPhillips' proposal to use good combustion practices and engineering design constitutes BACT.

2. Storage Tanks

VOC

ConocoPhillips' proposal to equip the No.5 HDS Feed storage tank with NSPS Subpart Kb and NESHAP Subpart CC IFR compliant seals and fittings and to maintain tank T-110 NSPS Subpart Kb and NESHAP Subpart CC compliant floating roof seals and fittings constitutes BACT.

3. Process Unit Fugitive Components

VOC

A search of EPA's RBLC database and recent Department decisions identified the implementation of LDAR programs as BACT. ConocoPhillips' proposal to incorporate the new fugitive components into its existing LDAR program, which meets or exceeds NESHAP Subpart CC and NSPS Subpart GGG requirements, constitutes BACT.

4. Deaerator Vent

VOC

Because the new No.2 H2 Unit will be designed and operated to ensure optimal conversion of hydrocarbon feeds and steam to hydrogen and $CO_2$, the emission of VOC will be minimized. 40 CFR 63 Subpart CC specifically exempts hydrogen production plant vents through which steam condensate produced or treated within the hydrogen plant is deaerated from MACT requirements. ConocoPhillips' proposal that optimal process design and proper operation of the No.2 $H_2$ Unit constitutes BACT.

5. Startup/Shutdown and Maintenance Wastewater Drains

VOC

A review of EPA's RBLC database and recent Department decisions identified water seals or other NESHAP Subpart FF and NSPS Subpart QQQ equivalent drains as BACT for wastewater drains. ConocoPhillips' proposal to install NESHAP Subpart FF and NSPS Subpart QQQ compliant drains constitutes BACT.

IV. Emission Inventory

| | | | Ton/Year | | | | | |
|---|---|---|---|---|---|---|---|---|
| Emission Point Number | Equipment Number | Source | $PM/PM_{10}$ | $NO_x$ | VOC | CO | $SO_2$ | TRS[1] |
| 41 | ULSD NH-1 | No.5 HDS Charge Heater | 0.96 | 3.81 | 0.70 | 7.75 | 2.29 | |
| 42 | ULSD NH-2 | No.5 HDS Reboiler Heater | 3.13 | 12.61 | 2.27 | 25.65 | 7.56 | |
| 43 | ULSD NH-3 | No.2 $H_2$ Reformer Heater | 2.50 | 15.77 | 1.13 | 32.06 | 3.78 | |
| 24 | | No.5 HDS Feed storage tank | | | 18.22 | | | |
| 26 | | Fugitives | | | 29.99 | | | 2.33 |
| 44 | | No.2 $H_2$ Deaerator Vent | | | 0.94 | | | |
| *35 | H-9401 | No.1 $H_2$ Heater | 0.55 | 2.04 | | 4.15 | 4.39 | |
| *24 | | Tank-110 | | | 1.99 | | | |
| *7 | H-10 | No.2 HDS | 0.08 | 1.03 | 0.06 | 0.87 | 1.40 | |
| *8 | H-11 | Debutanizer Reboiler No.2 HDS | 0.09 | 1.13 | 0.06 | 0.95 | 3.71 | |
| *9 | H-12 | Main Frac. Reboiler No.2 HDS | 0.21 | 2.75 | 0.15 | 2.31 | 5.46 | |
| *10 | H-13 | No.2 Reformer | 0.44 | 5.79 | 0.32 | 4.86 | 3.55 | |
| *11 | H-14 | No.2 Reformer | 0.01 | 0.13 | 0.01 | 0.11 | 1.14 | |
| *13 | H-16 | Stabilizer Reboiler, Sat Gas | 0.11 | 1.49 | 0.08 | 1.25 | 1.68 | |
| *20 | H-23 | No.2 Reformer | 0.49 | 6.43 | 0.35 | 5.40 | 3.40 | |
| *24 | | Tank-86 | | | 0.10 | | | |
| *1 | S-101/S-401 | Jupiter SRU | 0.37 | 1.92 | | | 0.95 | |
| | | **Total** | **8.94** | **54.90** | **56.37** | **85.36** | **39.31** | **2.33** |

1 Total Reduced Sulfur

- A complete emission inventory for Permit #2619-19 is on file with the Department.
- This emission inventory reflects only the current permit action.
- (*) Existing Sources expected to experience no increase in firing rates but a slight increase in actual emissions associated with the ULSD Project

**No.5 HDS Charge Heater**
29 MMBtu/hr

PM Emissions

Emission Factor 7.6 lb/MMscf (AP-42, Table 1.4-2)
Annual Calculation 29 MMBtu/hr* (7.6 lb/MMscf) * (1 MMscf NG / 1020 MMBtu) = 0.22 lb/hr
Hourly Calculation 0.22 lb/hr * (8760 hr/yr) * 0.0005 ton/lb) = 0.96 tpy

$NO_x$ Emissions

Emission Factor 0.03 lb/MMBtu (BACT Analysis (BACT))
Hourly Calculation 29 MMBtu/hr (0.03 lb $NO_X$/MMBtu) = 0.87 lb/hr
Annual Calculation 0.87 lb/hr (8760 hr/yr) * (0.0005 ton/lb) = 3.81 ton/yr

VOC Emissions

Emission Factor 5.5 lb/MMscf (AP-42, Table 1.4-2)
Annual Calculation 29 MMBtu/hr* (5.5 lb/MMscf) * (1 MMscf NG / 1020 MMBtu) = 0.16 lb/hr

| | |
|---|---|
| Hourly Calculation | 0.16 lb/hr (8760 hr/yr) * 0.0005 ton/lb) = 0.70 tpy |

CO Emissions

| | |
|---|---|
| Emission Factor | 61.0 lb/MMscf (AP-42, Table 1.4-1) |
| Hourly Calculation | 29 MMBtu/hr * (61.0 lb/MMscf) * (1 MMscf NG / 1000 MMBtu) = 1.77 lb/hr |
| Annual Calculation | 1.77 lb/hr * (8760 hr/yr) * (0.0005 ton/lb) = 7.75 ton/yr |

$SO_2$ Emissions

| | |
|---|---|
| NSPS J Limit | 0.10 gr/dscf $H_2S$ = 26.85 lb $SO_2$/MMscf at 60F |
| Proposed Limit | 0.073 gr/dscf $H_2S$ = |
| $H_2S$ at 60F | 379.5 scf $H_2S$/mol $H_2S$ |
| Molecular Weight $H_2S$ | 34.08 lb/lb-mol |
| Emission Factor | 0.073 gr/dscf * (1 lb / 7000 gr) * (379.5 dscf/lb-mol / 34.08 lb/lb-mol) * 1 X $10^6$ parts = 116.13 ppm $H_2S$ |
| Hourly $SO_2$ | (116.13 scf $H_2S$/MMscf fuel gas) * (1 mol $H_2S$ / 379.5 scf H2S) * 64.06 lb $SO_2$/mol $SO_2$ = 19.60 lb $SO_2$/MMscf fuel Gas |

| | |
|---|---|
| Hourly Calculation | 29 MMBtu/hr * (1 MMscf / 1089.6 MMBtu) * (19.60 lb/MMscf) = 0.52 lb/hr |
| Annual Calculation | 0.52 lb/hr (8760 hr/yr) * (0.0005 ton/lb) = 2.29 ton/yr |

## No.5 HDS Reboiler Heater

96 MMBtu/hr

PM Emissions

| | |
|---|---|
| Emission Factor | 7.6 lb/MMscf (AP-42, Table 1.4-2) |
| Annual Calculation | 96 MMBtu/hr* (7.6 lb/MMscf) * (1 MMscf NG / 1020 MMBtu) = 0.72 lb/hr |
| Hourly Calculation | 0.72 lb/hr * (8760 hr/yr) * 0.0005 ton/lb) = 3.13 tpy |

$NO_x$ Emissions

| | |
|---|---|
| Emission Factor | 0.03 lb/MMBtu (BACT Analysis (BACT)) |
| Hourly Calculation | 96 MMBtu/hr (0.03 lb $NO_X$/MMBtu) = 2.88 lb/hr |
| Annual Calculation | 2.88 lb/hr (8760 hr/yr) * (0.0005 ton/lb) = 12.61 ton/yr |

VOC Emissions

| | |
|---|---|
| Emission Factor | 5.5 lb/MMscf (AP-42, Table 1.4-2) |
| Annual Calculation | 96 MMBtu/hr* (5.5 lb/MMscf) * (1 MMscf NG / 1020 MMBtu) = 0.52 lb/hr |
| Hourly Calculation | 0.52 lb/hr (8760 hr/yr) * 0.0005 ton/lb) = 2.27 tpy |

CO Emissions

| | |
|---|---|
| Emission Factor | 61.0 lb/MMscf (AP-42, Table 1.4-1) |
| Hourly Calculation | 96 MMBtu/hr * (61.0 lb/MMscf) * (1 MMscf NG / 1000 MMBtu) = 5.74 lb/hr |
| Annual Calculation | 5.87 lb/hr * (8760 hr/yr) * (0.0005 ton/lb) = 25.65 ton/yr |

$SO_2$ Emissions

| | |
|---|---|
| NSPS J Limit | 0.10 gr/dscf $H_2S$ = 26.85 lb $SO_2$/MMscf at 60F |
| Proposed Limit | 0.073 gr/dscf $H_2S$ = |
| $H_2S$ at 60F | 379.5 scf $H_2S$/mol $H_2S$ |
| Molecular Weight $H_2S$ | 34.08 lb/lb-mol |
| Emission Factor | 0.073 gr/dscf * (1 lb / 7000 gr) * (379.5 dscf/lb-mol / 34.08 lb/lb-mol) * 1 X $10^6$ parts = 116.13 ppm $H_2S$ |
| Hourly $SO_2$ | (116.13 scf $H_2S$/MMscf fuel gas) * (1 mol $H_2S$ / 379.5 scf H2S) * 64.06 lb $SO_2$/mol $SO_2$ = 19.60 lb $SO_2$/MMscf fuel Gas |

| | |
|---|---|
| Hourly Calculation | 96 MMBtu/hr * (1 MMscf / 1089.6 MMBtu) * (19.60 lb/MMscf) = 1.73 lb/hr |
| Annual Calculation | 1.73 lb/hr (8760 hr/yr) * (0.0005 ton/lb) = 7.56 ton/yr |

## No.5 HDS Reboiler Heater

120 MMBtu/hr
48 MMBtu/hr w/ RFG
72 MMBtu/hr w/ PSA Gas

PM Emissions

| | |
|---|---|
| Emission Factor | 7.6 lb/MMscf (AP-42, Table 1.4-2) |
| Annual Calculation | 48 MMBtu/hr* (7.6 lb/MMscf) * (1 MMscf NG / 1020 MMBtu) = 0.36 lb/hr |
| Hourly Calculation | 0.36 lb/hr * (8760 hr/yr) * 0.0005 ton/lb) = 1.57 tpy |

| | |
|---|---|
| Emission Factor | 3.0 lb/MMscf (AFSCF, EPA 450/4-90-003 p.23)) |
| Annual Calculation | 72 MMBtu/hr* (3.0 lb/MMscf) * (1 MMscf NG / 1020 MMBtu) = 0.21 lb/hr |
| Hourly Calculation | 0.21 lb/hr * (8760 hr/yr) * 0.0005 ton/lb) = 0.93 tpy |

$NO_x$ Emissions

| | |
|---|---|
| Emission Factor | 0.03 lb/MMBtu (BACT Analysis (BACT)) |
| Hourly Calculation | 120 MMBtu/hr (0.03 lb $NO_X$/MMBtu) = 3.60 lb/hr |
| Annual Calculation | 3.60 lb/hr (8760 hr/yr) * (0.0005 ton/lb) = 15.77 ton/yr |

VOC Emissions

| | |
|---|---|
| Emission Factor | 5.5 lb/MMscf (AP-42, Table 1.4-2) |
| Annual Calculation | 48 MMBtu/hr* (5.5 lb/MMscf) * (1 MMscf NG / 1020 MMBtu) = 0.26 lb/hr |
| Hourly Calculation | 0.26 lb/hr (8760 hr/yr) * 0.0005 ton/lb) = 1.13 tpy |

CO Emissions

| | |
|---|---|
| Emission Factor | 61.0 lb/MMscf (AP-42, Table 1.4-1) |
| Hourly Calculation | 120 MMBtu/hr * (61.0 lb/MMscf) * (1 MMscf NG / 1000 MMBtu) = 7.32 lb/hr |
| Annual Calculation | 7.32 lb/hr * (8760 hr/yr) * (0.0005 ton/lb) = 32.06 ton/yr |

$SO_2$ Emissions

| | |
|---|---|
| NSPS J Limit | 0.10 gr/dscf $H_2S$ = 26.85 lb $SO_2$/MMscf at 60F |
| Proposed Limit | 0.073 gr/dscf $H_2S$ = |
| $H_2S$ at 60F | 379.5 scf $H_2S$/mol $H_2S$ |
| Molecular Weight $H_2S$ | 34.08 lb/lb-mol |
| Emission Factor | 0.073 gr/dscf * (1 lb / 7000 gr) * (379.5 dscf/lb-mol / 34.08 lb/lb-mol) * 1 X $10^6$ parts = 116.13 ppm $H_2S$ |
| Hourly $SO_2$ | (116.13 scf $H_2S$/MMscf fuel gas) * (1 mol $H_2S$ / 379.5 scf H2S) * 64.06 lb $SO_2$/mol $SO_2$ = 19.60 lb $SO_2$/MMscf fuel Gas |

| | |
|---|---|
| Hourly Calculation | 48 MMBtu/hr * (1 MMscf / 1089.6 MMBtu) * (19.60 lb/MMscf) = 0.86 lb/hr |
| Annual Calculation | 0.86 lb/hr (8760 hr/yr) * (0.0005 ton/lb) = 3.78 ton/yr |

## Tanks

## No.5 HDS Feed storage tank

From Tanks 4.09b

| | |
|---|---|
| VOC Emissions | 18.22 ton/yr |

## Tank-110

From Tanks 4.09b

VOC Emissions 1.99 ton/yr

**Fugitives**

VOC Emissions 29.99 ton/yr
$H_2S$ Emissions 2.33ton/yr

V. Existing Air Quality

ConocoPhillips is located at 401 South 23rd Street in Billings, Montana in the NW¼ of Section 2, Township 1 South, Range 26 East, in Yellowstone County. This area is considered attainment for all criteria pollutants. The Billings CO nonattainment area, which included ConocoPhillips, was reclassified to attainment by EPA's direct final rulemaking on April 22, 2002. The Laurel $SO_2$ nonattainment area is nearby.

VI. Ambient Air Impact Analysis

Environ International Corporation (Environ) conducted air quality modeling for the proposed ConocoPhillips ULSD Project as part of the ConocoPhillips air quality permit application. The modeling was done to demonstrate compliance with the Montana Ambient Air Quality Standards (MAAQS). A New Source Review (NSR) - PSD analysis was required for this permitting action.

The EPA approved Industrial Source Complex (ISC3) model and 7 years of meteorological data (1984 and 1986 through 1991) were utilized for the air quality model. The surface data was collected at the Billings International Airport National Weather Station, and the upper air data was collected at the Great Falls International Airport National Weather Station. The receptor grid used in this analysis consisted of a Cartesian grid with receptors spaced every 100 meters out to 1,000 meters and every 250 meters out to 3,000 meters, the facility's fenceline was represented with a receptor spaced every 50 meters. The receptor grid elevations were derived from digital elevation model (DEM) files using the United States Geological Survey (USGS) digitalized topographic maps. The Billings East, Billings West, Soda Springs Northwest, and Yegen quadrangles were used to determine the receptor grid. Building downwash was calculated using the EPA Building Profile Input Program (BPIP). The building corner coordinates and peak roof heights were used to determine the appropriate direction-specific building dimension parameters to use for each emission source evaluated in the model.

The modeled concentration was then compared against the "significant" levels for $NO_2$ emissions as shown in Table 1. The modeling results identified in Table 1 differ slightly from those submitted by Environ because the Department ran the model at the correct anemometer height of 7.62 meters and added some receptor elevations that were inadvertently left out.

Table 1. Modeling Results

| **Pollutant** | **Avg. Period** | **Easting (X) (m)** | **Northing (Y) (m)** | **Modeled Conc. ($\mu g/m^3$)** | **Significance Conc. ($\mu g/m^3$)** | **Percent of Significance (%)** |
|---|---|---|---|---|---|---|
| $NO_2$ | Annual | 696750.1 | 5073709 | 0.82 | 1 | 82 |

The results of the analysis show that the modeled $NO_X$ emissions from the proposed project at the refinery are less than the PSD modeling Significance level. Based on this demonstration, no further modeling is necessary and it is presumed that ConocoPhillips will not violate any ambient standard.

As part of the additional impacts analysis that was performed in accordance with the PSD requirements, ConocoPhillips also performed a visibility impairment analysis for Pompey's Pillar at the request of the Department. The analysis showed that proposed emission increases associated with the ULSD project do not have the potential to be perceptible to the casual observer. In other words, there will be no visibility impact in the surrounding Class II area due to the proposed project.

## VII. Taking or Damaging Implication Analysis

As required by 2-10-101 through 105, MCA, the Department conducted a private property taking and damaging assessment and determined there are no taking or damaging implications.

## VIII. Environmental Assessment

An environmental assessment, required by the Montana Environmental Policy Act, was completed for this project. A copy is attached.

DEPARTMENT OF ENVIRONMENTAL QUALITY
Permitting and Compliance Division
Air Resources Management Bureau
1520 East Sixth Avenue
P.O. Box 200901, Helena, Montana 59620-0901
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# FINAL ENVIRONMENTAL ASSESSMENT (EA)

Issued For: ConocoPhillips Company
Billings Refinery
P.O. Box 30198
Billings, MT 59107-0198

Permit Number: 2619-19

Preliminary Determination Issued: April 2, 2004
Department's Decision Issued: May 11, 2004
Final Permit Issued: May 27, 2004

1. Legal Description of Site: NW¼ of Section 2, Township 1 South, Range 26 East, Yellowstone County, Montana.

2. Description of Project: On February 3, 2004, the Department received a Montana Air Quality Permit Application from ConocoPhillips to modify Permit #2619-18 to add a new HDS Unit (No.5), a new sour water stripper (No.3 SWS), and a new $H_2$ Unit. On March 1, 2004, the Department deemed the application complete upon submittal of additional information. The addition of these new units adds three new heaters, 41, 42, and 43, each equipped with low nitrogen oxides ($NO_X$) burners (LNB) and flue gas recirculation (FGR) commonly referred to as ultra-low $NO_X$ burners (ULNB). Additionally, ConocoPhillips proposes to retrofit existing external floating roof tank T-110 with a cover to allow nitrogen blanketing of the tank, to install a new storage vessel (No.5 HDS Feed storage tank) under emission point 24 above, to store feed and off-specification material for the No.5 HDS Unit, and to provide the No.1 $H_2$ Unit with the flexibility to burn refinery fuel gas (RFG). The new equipment is being added to meet the new Environmental Protection Agency (EPA)-required highway ultra low sulfur diesel (ULSD) fuel sulfur standard of 100% of highway diesel that meets the 15 parts per million (ppm) highway diesel fuel maximum sulfur specification by June 1, 2006. By meeting the June 1, 2006, deadline, ConocoPhillips may claim a two-year extension for the phase in of the requirements of the Tier Two Gasoline/Sulfur Rulemaking. This permitting action results in $NO_X$ and volatile organic compound (VOC) emissions that exceed Prevention of Significant Deterioration (PSD) significance levels. Other changes are also contained in this permit. Previously in permit condition II.A.1 it was stated that the emergency flare tip must be based at 148-feet elevation. After a physical survey of the emergency flare it was determined that the actual height of the flare tip is 141.5-feet elevation. The current permit changes permit condition II.A.1 from 148-feet of elevation to 142-feet plus or minus 2 feet of elevation and changes the reference from ARM 17.8.752 to ARM 17.8.749. Permit #2619-19 has also been updated to reflect current permit language and rule references used by the Department.

3. Objectives of Project: The new equipment is being added to meet the new EPA-required highway ULSD fuel sulfur standard of 100% of highway diesel that meets the 15 ppm highway diesel fuel maximum sulfur specification by June 1, 2006. By meeting the June 1, 2006, deadline, ConocoPhillips may claim a two-year extension for the phase in of the requirements of the Tier Two Gasoline/Sulfur Rulemaking.

4. Alternatives Considered: In addition to the proposed action, the Department also considered the "no-action" alternative. The no-action alternative would deny issuance of the air quality preconstruction permit to ConocoPhillips. However, the "no action" alternative was dismissed because ConocoPhillips demonstrated compliance with all applicable rules and standards as required for permit issuance.

5. A Listing of Mitigation, Stipulations, and Other Controls: A list of enforceable conditions including a BACT analysis would be contained in Permit #2619-19.

6. Regulatory Effects on Private Property: The Department considered alternatives to the conditions imposed in this permit as part of permit development. The Department determined that the permit conditions would be reasonably necessary to ensure compliance with applicable requirements and demonstrate compliance with those requirements and would not unduly restrict private property rights.

7. The following table summarizes the potential physical and biological effects of the proposed project on the human environment. The "no-action" alternative was discussed previously.

| | | **Major** | **Moderate** | **Minor** | **None** | **Unknown** | **Comments Included** |
|---|---|---|---|---|---|---|---|
| A | Terrestrial and Aquatic Life and Habitats | | | X | | | Yes |
| B | Water Quality, Quantity, and Distribution | | | X | | | Yes |
| C | Geology and Soil Quality, Stability, and Moisture | | | X | | | Yes |
| D | Vegetation Cover, Quantity, and Quality | | | X | | | Yes |
| E | Aesthetics | | | X | | | Yes |
| F | Air Quality | | | X | | | Yes |
| G | Unique Endangered, Fragile, or Limited Environmental Resources | | | | X | | Yes |
| H | Demands on Environmental Resource of Water, Air and Energy | | | X | | | Yes |
| I | Historical and Archaeological Sites | | | X | X | | Yes |
| J | Cumulative and Secondary Impacts | | | X | | | Yes |

SUMMARY OF COMMENTS ON POTENTIAL PHYSICAL AND BIOLOGICAL EFFECTS: The following comments have been prepared by the Department.

A. Terrestrial and Aquatic Life and Habitats

This permitting action would have a minor effect on terrestrial and aquatic life and habitats, as the proposed project would affect an existing, industrial property that has already been disturbed. Increases in $NO_X$, VOC, particulate matter (PM), carbon monoxide (CO), and sulfur oxides ($SO_X$) emissions would be expected as a result of this project, but would have only a minor impact, if any, on existing terrestrial and aquatic life and habitats of the area because the proposed project would occur on industrial property that has already been disturbed. This permitting action contains $NO_X$ and VOC emissions that exceed PSD significance levels.

B. Water Quality, Quantity, and Distribution

This permitting action would have little or no effect on the water quality, water quantity, and distribution, as there would be no discharges to groundwater or surface water associated with this project. Any wastewater produced as a result of the project would be treated in the current wastewater treatment systems on site at ConocoPhillips. Increases in $NO_X$, VOC, PM, CO, and $SO_X$ emissions would be expected as a result of this project, but should have only a minor impact, if any, on water quality, quantity, and distribution in the area because the proposed project would occur on industrial property that has already been disturbed. In addition, the facility would emit air pollutants and corresponding deposition of pollutants would occur; however, as described in Section 7.F. of this EA, the Department determined, based on ambient air quality modeling, that the chance of deposition of pollutants impacting water quality, quantity, and distribution would be minor.

C. Geology and Soil Quality, Stability, and Moisture

This permitting action would have a minor effect on geology and soil quality, stability, and moisture, as the proposed project would affect an existing industrial property that has already been disturbed. No additional land would be disturbed for the project. The increase in $NO_X$, VOC, PM, CO, and $SO_X$ emissions for this project may have a minor effect on the soil stability and moisture; however, the air quality permit associated with this project would contain limitations to minimize the effect of the emissions (New Source Performance Standards and current permit limitations) on the surrounding environment. Further, deposition of pollutants would occur; however, as described in Section 7.F of this EA, the Department, based on the proposed projects percentage of the PSD Significance level determined in the ambient air quality modeling, determined the chance of deposition of pollutants impacting the quality of the soil in the areas surrounding the site would be minor.

D. Vegetation Cover, Quantity, and Quality

This permitting action would have a minor effect on vegetation cover, quantity, and quality. The proposed project would affect an existing industrial property that has already been disturbed. No additional vegetation on the site would be disturbed for the project. The increase in $NO_X$, VOC, PM, CO, and $SO_X$ emissions for this project may have a minor effect on the surrounding vegetation; however, the air quality permit associated with this project would contain limitations to minimize the effect of the emissions (New Source Performance Standards and current permit limitations) on the surrounding environment. The facility would be a source of air pollutants and corresponding deposition of pollutants would occur; however, as described in Section 7.F of this EA, the Department determined, based on the pollution concentrations determined in the ambient air quality modeling, the chance of deposition of pollutants impacting the vegetation in the area surrounding the site would be minor.

E. Aesthetics

The proposed modification to the facility would be constructed in an area that has previously been disturbed and already has noise associated with its operations. The construction involved in the project would be limited to the addition of three new heaters and minor modifications of current processes. The change in utilization of the current processes would also not change the current nature of the facility with respect to appearance or noise. Therefore, only minor impacts to aesthetics are anticipated.

F. Air Quality

There would be air quality impacts resulting from the proposed project. The ULSD Project to the main boilerhouse would be subject to New Source Performance Standards (NSPS, 40 CFR Part 60), National Emission Standards of Hazardous Pollutants (NESHAPS 40 CFR Part 61 and 40 CFR Part 63), and therefore the control methods required by the associated Subparts. The BACT analysis in Permit #2619-19 also concluded that compliance with the proposed limits and the use of ULNBs constitutes BACT for this action. The following table displays the potential controlled emissions from the ULSD Project.

| | $PM/PM_{10}$ | CO | $NO_X$ | VOC | $SO_X$ |
|---|---|---|---|---|---|
| **Project-Related Increase in Emissions (tons/year)** | 10.53 | 85.36 | 54.90 | 8.75 | 39.31 |

ConocoPhillips would be required to maintain compliance with the Billings/Laurel $SO_2$ State Implementation Plan (SIP), its current permit conditions, and state and federal ambient air quality standards. Based on the required compliance with existing permit conditions and the required compliance with NSPS, NESHAPS, and BACT for the ULSD Project, the effect on air quality would be minor.

G. Unique Endangered, Fragile, or Limited Environmental Resources

This permitting action would not result in impacts to terrestrial and aquatic life and/or their habitat; therefore, unique, rare, threatened, or endangered species would not experience impacts. The Department is not aware of any unique, rare, threatened, or endangered species in the area surrounding the facility. There would not be any additional impact to these resources because the project would occur at an already disturbed site.

H. Demands on Environmental Resource of Water, Air, and Energy

As described in Section 7.B of this EA, this permitting action would have little or no effect on the environmental resource of water as there would be no discharges to groundwater or surface water associated with this permitting action. Any wastewater produced as a result of the project would be treated in the current wastewater treatment systems on site at ConocoPhillips.

As described in Section 7.F of this EA, the impact on the air resource in the area of the facility would be minor because the facility would be required to maintain compliance with other limitations affecting the overall emissions from the facility.

A minor impact to the energy resource is expected due to the utilization of the ULSD Project. However, as no major new energy consuming equipment would be added only exchanged and no utility upgrade would be required as a result of these changes, the impact to the energy resource would be minor.

I. Historical and Archaeological Sites

The project would occur within the boundaries of the area already disturbed. Previous correspondence between the Department and the Montana Historical Society – State Historic Preservation Office (SHPO) indicates that because industrial activities and land disturbances have occurred in the area, the likelihood of finding undiscovered or unrecorded historical properties on the ConocoPhillips property is unlikely. Therefore, the chance to affect a historical and archaeological site as a result of this project would be minor.

J. Cumulative and Secondary Impacts

Increases in actual pollutant emissions above historical levels may result in minor cumulative and secondary impacts to terrestrial and aquatic habitats, water quality, and air quality. Minor cumulative or secondary impacts are expected to result from this project. Due to the size of the project, the industrial production, employment, tax revenue (etc.), and the fact that the result of the project would be the production of diesel with lower sulfur content, changes resulting from the proposed project would be minor. In addition, the Department believes that this facility could be expected to operate in compliance with all applicable rules and regulations as would be outlined in Permit #2619-19.

Any future facility changes greater than 15 tons per year would require ConocoPhillips to apply for and receive the appropriate permits from the appropriate regulating authority. Impacts from any future facility changes would be assessed through the appropriate permitting process.

8. The following table summarizes the potential economic and social effects of the proposed project on the human environment. The "no-action" alternative was discussed previously.

| | | Major | Moderate | Minor | None | Unknown | Comments Included |
|---|---|---|---|---|---|---|---|
| A | Social Structures and Mores | | | | X | | Yes |
| B | Cultural Uniqueness and Diversity | | | | X | | Yes |
| C | Local and State Tax Base and Tax Revenue | | | X | | | Yes |
| D | Agricultural or Industrial Production | | | X | | | Yes |
| E | Human Health | | | X | | | Yes |
| F | Access to and Quality of Recreational and Wilderness Activities | | | | X | | Yes |
| G | Quantity and Distribution of Employment | | | | X | | Yes |
| H | Distribution of Population | | | | X | | Yes |
| I | Demands for Government Services | | | X | | | Yes |
| J | Industrial and Commercial Activity | | | X | | | Yes |
| K | Locally Adopted Environmental Plans and Goals | | | | X | | Yes |
| L | Cumulative and Secondary Impacts | | | X | | | yes |

SUMMARY OF COMMENTS ON POTENTIAL ECONOMIC AND SOCIAL EFFECTS: The following comments have been prepared by the Department.

A. Social Structures and Mores

The proposed project would not cause a disruption to any native or traditional lifestyles or communities (social structures or mores) in the area because the project would be constructed at a previously disturbed, industrial site and would not change the nature of the site.

B. Cultural Uniqueness and Diversity

The proposed project would not cause a change in the cultural uniqueness and diversity of the area because the land is currently used as a petroleum refinery; therefore, the land use would not be changing.

C. Local and State Tax Base and Tax Revenue

The proposed project would have a minor effect on the local and state tax base and tax revenue because the new equipment associated with the ULSD Project may be subject to property taxes. However, any possible increases in property taxes associated with the project would be minor. No new employees would be added as a result of this project. Tax revenue from the facility might increase slightly.

D. Agricultural or Industrial Production

This project would not result in a reduction of available acreage or productivity of any agricultural land; therefore, agricultural production should not be affected. No impacts on agricultural and industrial production would result from this project. Deposition of pollutants would occur; however, the Department determined the chance of deposition of pollutants impacting agricultural or industrial production in the area surrounding the site would be minor.

E. Human Health

As described in Section 7.F of the EA, the impacts from the proposed project on human health would be minor because the emissions of $NO_X$, VOC, PM, CO, and $SO_X$ from the facility would increase moderately. The air quality permit for this facility incorporates conditions to ensure that the facility would be operated in compliance with all applicable rules and standards. These rules and standards are designed to be protective of human health.

F. Access to and Quality of Recreational and Wilderness Activities

The proposed action would not alter any existing access to or quality of any recreational or wilderness area. This project would not have an impact on recreational or wilderness activities because the site is far removed from recreational and wilderness areas or access routes.

G. Quantity and Distribution of Employment

The proposed project would not result in any impacts to the quantity or distribution of employment at the facility or surrounding community. No employees would be hired at the facility as a result of the project.

H. Distribution of Population

The proposed project does not involve any significant physical or operational change that would affect the location, distribution, density, or growth rate of the human population of the area.

I. Demands for Government Services

The demands on government services would experience a minor impact. The primary demand on government services would be the acquisition of the appropriate permits by the facility (including local building permits, as necessary, and a state air quality permit) and compliance verification with those permits.

J. Industrial and Commercial Activity

Industrial production and commercial activity at the facility, or in the neighboring area, is not anticipated to change from issuing Permit #2619-19.

K. Locally Adopted Environmental Plans and Goals

The Department is unaware of any locally adopted environmental plans and goals that would be affected by the proposed change to the facility. The conditions associated with the Billings/Laurel $SO_2$ SIP would apply regardless.

L. Cumulative and Secondary Impacts

Minor cumulative and secondary impacts to the human environment may result because of increases in actual pollutant emissions above historical levels. Minor cumulative or secondary impacts are expected to result from this project.

Recommendation: An EIS is not required.

If an EIS is not required, explain why the EA is an appropriate level of analysis: The impacts resulting from this project would be limited to the ULSD Project. An increase in $NO_X$, VOC, PM, CO, and $SO_X$ emissions above currently permitted levels are expected.

Other groups or agencies contacted or which may have overlapping jurisdiction: None.

Individuals or groups contributing to this EA: Montana Department of Environmental Quality – Air Resources Management Bureau.

EA prepared by: Chris Ames
Date: 03/30/04